Demand, Energy, and Power Factor

A Report

by

Michael J. Gough

Submitted to the Department of Mechanical Engineering
of Texas A&M University
in partial fulfillment of the requirements for the degree of

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14. Abstract Energy audits have been performed by the Energy Systems Laboratory's Industrial Assessment Center (IAC) at Texas A & M University since 1986. Often, energy conservation opportunities (EOCs) are identifiable prior to visiting the plant, from the analysis of utility data. This paper is a study of the utility data which plants provide to the IAC, and in particular, the effects of demand, block extenders, and power factor on plant utility costs and energy conservation costs. Education of plant personnel about these effects is also described. Another purpose of this report is to provide a listing of types of typical savings potentials available to industrial plants for the three subjects presented. Explanations of lowering demand, demand-leveling, and power factor correction will be presented to provide typical savings encountered by the IAC at industrial plants. The utility rate schedules considered in this report are from California, Illinois, Texas, and Virginia, and are listed at Table 1, along with the major military installations served by the utility.

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ABSTRACT

This paper briefly presents the results of a study of various utility rate schedules from across the United States and describes a video produced to explain some major features of these rate structures. In particular, the demand, energy and power factor sections of each rate schedule are explored to understand the impacts of selected features on utility costs and on evaluation of energy conservation projects.

The accompanying video was produced for the Energy Systems Laboratory's Industrial Assessment Center (IAC) at Texas A&M University. This video will be used during industrial audits to explain typical demand, energy and power factor structures and savings potentials that can be realized by implementation of energy conservation retrofit projects, known as energy conservation opportunities (ECO's), that may be presented through the energy audit process.

ACKNOWLEDGMENTS

I would like to express my heartfelt appreciation and gratitude to Dr. Warren M. Heffington for his generous assistance, encouragement, and advice during the course of study. My sincere appreciation is extended to Dr. Dennis O'Neal and Professor Doug Tiner for their advice and comments as committee members. I would also like to thank all my IAC colleagues, Commander Thomas Holt, USN, and friends for their help. I wish to thank my mother for her moral support.

CHAPTER I

INTRODUCTION

PURPOSE

Energy audits have been performed by the Energy Systems Laboratory's Industrial Assessment Center (IAC) at Texas A&M University since 1986. Often, energy conservation opportunities (ECO's) are identifiable prior to visiting the plant, from the analysis of utility data. This paper is a study of the utility data which plants provide to the IAC, and in particular, the effects of demand, block extenders, and power factor on plant utility costs and energy conservation costs. Education of plant personnel about these effects is also described.

Much information exists about rate schedules, demand, block extenders and power factor (Turner 1993).[1] An annotated bibliography of some publications with general information is included as Appendix A. Typically, plant managers and maintenance personnel have a basic understanding of these subjects, but not in sufficient detail to apply them to save energy and money.

One of the results of the IAC's one-day audits is to present, in a short period of time, an instruction period on demand, block extenders, and power factor for the plant management to use and save both energy and money from their utilities. This report, with its accompanying video, is provided as a short instruction course on demand, block extenders and power factor.

Another purpose of this report is to provide a listing of typical savings potentials available to industrial plants for the three subjects presented. Explanations of lowering demand, demand leveling, and power factor correction

[1] The format of the references in this report follows that of the Transactions of ASHRAE, the American Society of Heating, Refrigerating, and Air-Conditioning Engineers, Inc.

will be presented to provide typical savings encountered by the IAC at industrial plants.

DATA PROCUREMENT

Information on demand, block extenders and power factor can be found in many sources (e.g., Turner 1993). The available sources do not deal with specifics about each area of the country. This report will deal with specifics of several utility rate schedules from across the United States. The sampling of different utility rate schedules was chosen to provide a wide variety of features, and to include some for important naval installations. Particularly, they have differences in charges for demand, energy consumption, and power factor. Copies are included in Appendix B for reference.

The utility rate schedules considered in this report are from California, Illinois, Texas, and Virginia, and are listed in Table 1, along with the major military installations served by the utility. All the schedules are applicable to major military installations except for the Houston Lighting and Power and City of Brenham schedules. Many military installations' rate schedules are similar to the schedules considered in this analysis.

TABLE 1
Rate Schedules and Military Installations Served

Utility Name & Location	Major Military Installation	Rate Schedule Designation
Commonwealth Edison Chicago, IL	Great Lakes Naval Station	6L, Large General Service, Time-of-Day
San Diego Gas and Electric, San Diego, CA.	San Diego Naval Station	AL-TOU, General Service-Large-Time Metered
Houston Lighting and Power Houston, TX	None	HL&P 67, Large General Service
City of Brenham Brenham, TX	None	E-G, Small Industrial Service
Virginia Electric and Power Norfolk, VA	Norfolk Naval Station	MS

Other portions of this study will present information that was experienced as a direct participant in IAC audits and listening to plant representatives' questions during audits. Also included are experiences of other students involved in IAC audits.

CHAPTER II

RATE STRUCTURE FEATURES

DEMAND MEASUREMENT

Demand is the rate at which electrical energy is used. It is usually billed explicitly only at commercial or industrial facilities. Most rate structures express charges based on real power in kilowatts (kW), but some use apparent power expressed in kilovolt-amperes (kVA).

Demand meters are typically installed at the utility side of the facilities' incoming electrical feed. These meters are either electro-mechanical or electronic in nature. They measure and record the highest peak demand encountered in the billing period, usually about one month. The peak demand will normally be measured over a five to fifteen-minute period. However, some utilities extend the measurement time up to sixty minutes. Of the five utility rate structures provided in Appendix B, three use 15-minute intervals and the other two use 30-minute intervals.

The advantage of having a longer peak demand interval exists in a situation where a facility has large hoists, elevators, furnaces, or other large electrical loads where the energy demand is intermittent or subject to large, transient fluctuations. Some utilities will take this into account and provide a longer interval of peak demand measurement, if requested.

DEMAND STRUCTURES

There are some typical demand features, such as block structure, time-of-day rates, and seasonal variations that are seen in almost all utility rate structures. The rate schedules used in this study are either large general

service (LGS) or industrial type rate schedules. Three of the five schedules are applicable to large military bases and two are from the local Texas area.

Table 2 below shows the time-of-day and seasonal variations (summer only) for the five utility rate structures in this study. The peak time-of-day generally includes the late morning and afternoon hours, when there are relatively large cooling loads and homemaking activities. Sometimes, it is restricted to week days (e.g., Commonwealth Edison, Virginia Electric and Power, Houston Lighting and Power, and San Diego Gas and Electric, included in Appendix B).

TABLE 2
Time-of-Day and Seasonal Variations

Utility Name	Peak Time-of-Day	Seasonal Variation
Commonwealth Edison	9 a.m. - 10 p.m. (Monday - Friday)	June 15 - September 15 (summer)
San Diego Gas and Electric	11 a.m. - 6 p.m. (Monday - Friday)	May 1 - September 30 (summer)
Houston Lighting and Power	8 a.m. - 10 p.m. (Monday - Friday)	May 15 - October 15 (summer)
City of Brenham	Various (Coincident on-peak)	June 1 - September 30 (summer)
Virginia Electric and Power	7 a.m. - 10 p.m. (Monday - Friday)	None

Some examples of time-of-day cost variations can be clearly seen in the Commonwealth Edison and San Diego Gas and Electric demand rate schedules. For Commonwealth Edison, the summer rates are $17.15/kW in the peak time period and $7.43/kW in the off-peak period. The winter demand rates for Commonwealth Edison are $13.42/kW and $5.76/kW in the peak and off-peak periods, respectively. San Diego Gas and Electric is similar to the

Commonwealth Edison demand rate structure with summer rates of $18.14/kW and $3.35/kW, and winter rates of $4.21/kW and $3.35/kW for the peak and off-peak periods.

This shows that when the utility is experiencing its highest system loads, the customer will pay more for its demand. This encourages the customer to schedule his work periods to the off-peak times to reduce the charges for demand.

The one exception regarding seasonal variations in Table 2 is Virginia Electric and Power Company. Their lack of seasonal variations could not be explained by either a major customer (Eitel 1993) or the utility company representative (Thomas 1993).

The seasonal variations shown in Table 2 are for the summer season only. Typically, these extend from approximately May to September, which would normally be the peak time of year for cooling loads. The winter season, not shown in Table 2, is all the other months. The peak loads for the winter months would include large heating loads, if electricity were used for heating.

Demand rates can have block structures, similar to energy rate block structures. An example is the Virginia Electric and Power Company demand rates in Appendix B. For the first 1,500 kW demand the utility charges $12.97947/kW and for all additional demand above 1,500 kW the utility charges $12.61638/kW. Commonwealth Edison has a similar demand structure, with the first 10,000 kW costing $17.15/kW and $13.42/kW in the summer and winter months, respectively, and with demand over 10,000 kW costing $7.43/kW and $5.76/kW, respectively.

All peak demand rates have as a purpose the lowering of demand at the peak time of the supplier. However, peak charges applied over a broad interval such as those from Virginia Electric and Power, San Diego Gas and Electric, and

Houston Lighting and Power do not focus on the precise time of the peak as well as possible. An interesting demand charge is the coincident/non-coincident peak demand charge of the City of Brenham. This charge is a penalty to the customer for demand occurring precisely when the utility has its peak demand. For the City of Brenham demand rate structure, the utility charges a coincident peak charge at the time of the system peak for the Lower Colorado River Authority (LCRA), a major regional wholesale supplier. The customer's demand window is 15-minutes averaged over one hour, and it must occur within 30 minutes of the LCRA system peak to be a coincident peak.

This rate is of interest because of the precision with which it tracks the supplier's peak. Table 3 (Carney, et.al. 1994) shows the time and dates of the LCRA system demand peaks for a recent year. There are some early morning peaks which would fall outside the time-of-day and seasonal periods shown in Table 2. However, the LCRA is an unusual utility with some hydroelectric production, and a relatively large number of rural and small town consumers.

TABLE 3
LCRA Coincident Peak Demand Times and Dates

Billing Date	Time of Peak	Peak Demand Date
12/25/92	19:00	12/05/92
01/25/93	08:00	01/11/93
02/25/93	08:00	01/26/93
03/25/93	09:00	03/13/93
04/25/93	21:00	04/19/93
05/25/93	18:00	05/17/93
06/25/93	17:00	06/03/93
07/25/93	17:00	07/23/93
08/25/93	18:00	08/18/93
09/25/93	18:00	08/25/93
10/25/93	17:00	09/25/93
11/22/93	07:00	11/05/93

Because the utility establishes a non-coincident peak demand charge, cost savings can be seen by the customer if their peak demand does not occur when the utility reaches its peak demand. For the City of Brenham rate structure in Appendix B, the coincident on-peak demand charge is $9.061/kW and the non-coincident peak demand charge is $1.2603/kW, or a $7.8007/kW difference. Therefore, a customer should be aware of when the coincident on-peak time occurs. Table 3 shows that the LCRA peak generally occurs at about 5 p.m. during April through December, and about 8 a.m. during January through March. This is fairly consistent from year to year (Dannhaus 1994). Arrangements can be made to have the utility notify the customers of the impending peak so that equipment can be shutoff, or to even have the utility control the equipment by radio signal.

ENERGY RATE STRUCTURES

Utility energy rate structures can vary significantly across the country. Each utility rate structure is dependent on the customer base size, the types of customers and other economic factors. Some of the more prevalent energy rate structures are the flat block, fixed declining block, flexible declining block, and time-of-day dependent. Table 4 shows each utility, the number of energy blocks the rate structure has, and whether it is a flat, fixed declining,[2] or flexible declining, or time-of-day dependent energy rate block structure.

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[2] None of the rate structures considered in this report exhibit true fixed declining block behavior. An example of a fixed declining block structure would be a rate schedule charging a higher price for the first 500,000 kWh of energy, and a lower price for all additional energy used.

TABLE 4
Utility Energy Rate Structures

Utility Company & Energy Rate Schedule	No. of Blocks	Type of Structure
Commonwealth Edison, LGS-TOD	two	time-of-day dependent
San Diego Gas and Electric, AL-TOU	three	time-of-day dependent
Houston Lighting and Power, LGS	two	flexible declining (demand dependent)
City of Brenham, E-G	one	flat
Virginia Electric and Power Company, MS	one	flat

Flat Block Rate Structure

The simplest of the energy rate structures is the flat block rate structure, in which one flat rate is charged for all kilowatt-hours consumed in the plant. There is no correlation between energy charges and demand. The two rate schedules in Table 4 which have this structure are the City of Brenham and Virginia Electric and Power Company. The energy charges for these utilities are \$0.00880/kWh and \$0.01968/kWh, respectively.

Time-of-Day Dependent Rate Structure

The San Diego Gas and Electric and Commonwealth Edison energy rate structures are time-of-day dependent, multi-block rate structures. Both energy rate structures have a dependency on the time-of-day when the energy is used.

For the San Diego Gas and Electric Company primary voltage, large general service, time metered schedule there are three blocks of time which

regulate the charges for energy consumption. The three time periods are noted as on-peak, semi-peak, and off-peak. Table 5 shows the three time periods, the applicable base energy rates, and the seasonal adjustments to the time periods. The times listed are weekdays, unless specified.

TABLE 5
San Diego Gas and Electric Energy Rates and Times

Period	Summer Rate ($/kWh)	Winter Rate ($/kWh)	Summer Times	Winter Times
Peak	0.05000	0.03035	11 a.m. - 6 p.m.	5 p.m. - 8 p.m.
Semi-peak	0.00927	0.00947	6 a.m. - 11 p.m. 6 p.m. - 10 p.m.	6 a.m. - 5 p.m. 8 p.m. - 10 p.m.
Off-peak	0.00059	0.00094	10 p.m. - 6 a.m. plus holidays and weekends	10 p.m. 6 a.m. plus holidays and weekends

Table 5 shows that the cost of energy is less expensive when the consumption is during the semi-peak or off-peak time period. This is reasonable, because the utility would not have much trouble generating enough energy to service all its customers at semi-peak or off-peak times. Off-peak rates are about one-tenth (or less) of semi-peak rates, and are about one-thirtieth (or less) of peak rates. The winter peak rate is about 60% of the summer peak rate, attributed to a much lower cooling load. The dramatic difference between the summer peak and off-peak rates (the off-peak summer rate is even less than the winter off-peak rate) strongly encourages energy use at other than peak times.

The second energy rate schedule for the time-of-day dependent rate structure is the Commonwealth Edison Company. This energy schedule has only two blocks, which are the peak and off-peak time periods. The peak period is from 9:00 a.m. to 10:00 p.m., Monday through Friday, except for holidays. All

other times are considered as off-peak. The rate for the peak period is $0.05741/kWh and during the off-peak period the utility charges $0.02477/kWh.

Flexible Declining Rate Structure

As noted in Table 3, this rate structure is dependent on the peak demand of the plant and cost savings for energy are available as a result of lowering demand, which will be discussed in Chapter III. Houston Lighting and Power (HL&P) bills its customers based on apparent demand, measured in kilovolt-amperes (kVA).

For the rate schedule used in this study, HL&P - Large General Service (LGS), the cost for energy consumption in the second block is cheaper than for the first block. The first block energy charge is $0.025734/kWh for the first 295 kWh/kVA demand, and the second block energy charge is $0.007540/kWh. The size of the first block depends on demand, and the factor of 295 kWh/kVA, which determines the block size and is called a block extender.

To illustrate, consider a demand of 1,000 kVA with an energy consumption of 350,000 kWh, for a one month utility bill. The resultant demand, energy and total costs are $6,820, $8,006, and $14,826, respectively. Figure 1 is a graphical representation of the results. Note that in Figure 1 the block 1 energy cost is $7,591.53 (295,000 kWh at $0.025734/kWh) and the block 2 energy cost is $414.70 (55,000 kWh at $0.00754/kWh).

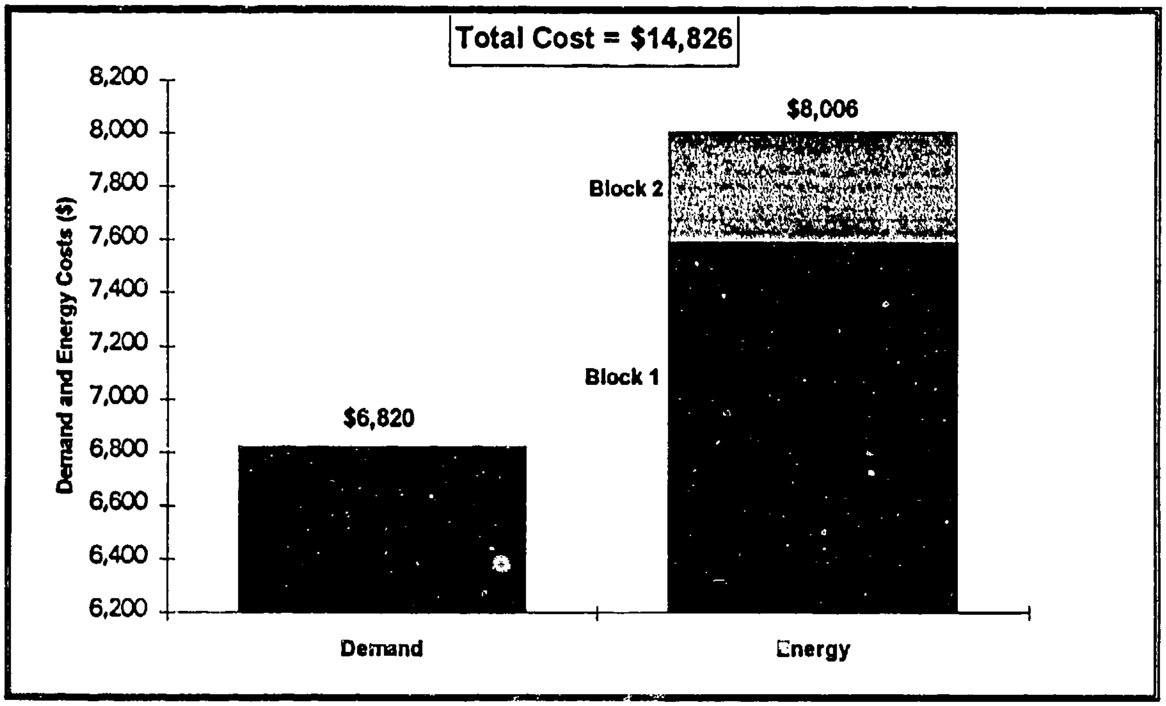

FIGURE 1
Houston Lighting and Power Rate Structure Example

If demand is lowered in the above example, for the same amount of energy use, the size of the more expensive first block decreases and more energy is in the less expensive second block. If the peak demand of the plant is reduced, a savings for both demand and energy can result. Consider lowering the demand from 1000 kVA to 900 kVA, with the total consumption remaining the same (350,000 kWh). There would be a savings for both demand and energy costs. The costs would be $6,138 for demand and $7,470 for energy, for a total cost of $13,608. Now, only 265,500 kWh (900 kVA multiplied by the block extender factor of 295 kWh/kVA) are charged at the more expensive block 1 price of $0.025734/kWh for a cost of $6,832.37, and the remainder (84,500 kWh) of the 350,000 kWh is charged at $0.00754/kWh for a cost of $637.13.

Therefore, with a flexible declining block energy rate structure, which is demand dependent, and with consumption in two blocks, if the customer lowers demand by turning off equipment or extending the shift time, savings occur in

both energy and demand. Some methods for lowering demand and demand leveling will be discussed more in Chapter III.

As noted earlier, HL&P measures demand in kVA. The major advantage to measuring demand in kVA is that equipment inefficiency and electrical losses become the customers responsibility. According to the Electric Power Research Institute (EPRI) in Palo Alto, California (Evans 1994) there are at least fifty other utilities nation-wide which bill on kVA demand.

Several other charges are also imposed on a kWh basis by all utilities. Examples include fuel cost adjustments and power cost recovery adjustments. These are usually charged on a flat energy rate basis and vary in the type and amount from utility to utility.

POWER FACTOR DEFINITION

Basically, power factor (pf) is a measure of how effectively the plant uses the electricity it purchases from the utility. It is defined as the ratio of real power to apparent power with units of kW/kVA, and frequently it is expressed as a percentage. It is also given as the cosine of the angle between the apparent power hypotenuse and the real power leg of a right triangle when the powers are described in the complex plane. In equation form:

$$\text{pf} = \frac{\text{Real Power (kW)}}{\text{Apparent Power (kVA)}} = \text{cosine } \theta$$

In an alternating current (AC) circuit there are three electric powers that are normally defined. Real power is the power which the equipment in the plant actually uses to do work and apparent power is the power the utility supplies to run the equipment. The last power defined is imaginary or reactive power,

expressed in kilovolt amperes reactive (kVAR). Reactive power does no useful work in an AC electrical system. This can be described in the complex plane by associating the real power with the real axis and the reactive or imaginary power with the imaginary axis. The apparent power is then the vector sum of the real and imaginary powers as shown in Figure 2.

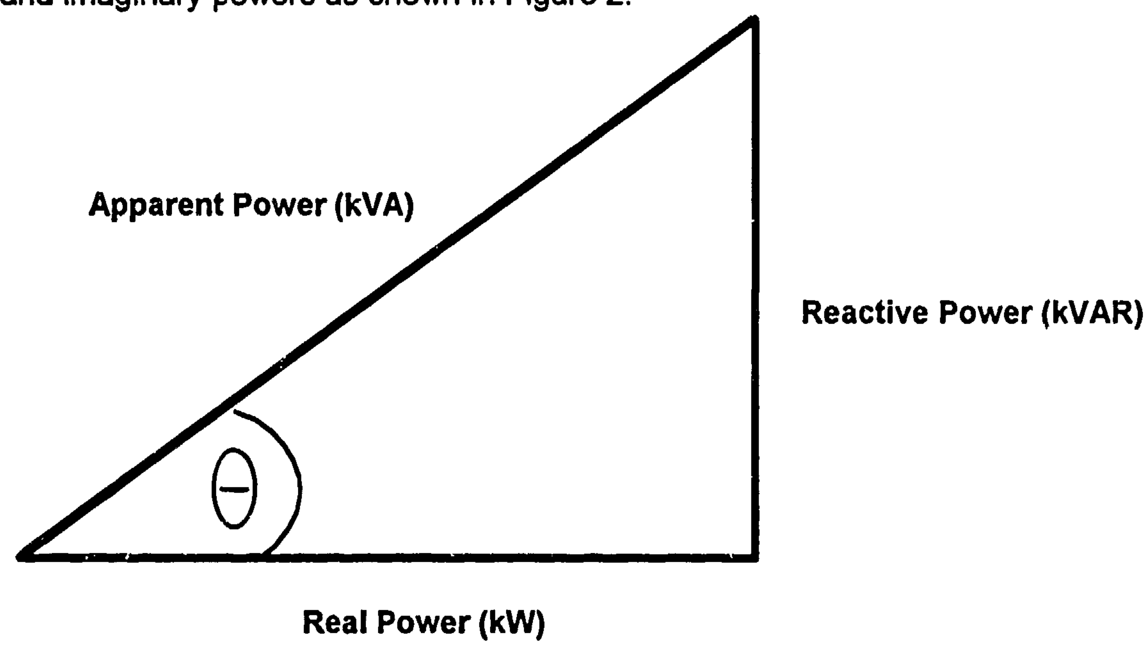

FIGURE 2
Power Triangle

Most utility companies have some method to penalize the customer if their power factor is not above some specified level. Generally, power factors below 75% to 85% are penalized. Four of the five utilities in Table 1 have specific or implied power factor penalties.

For the City of Brenham and San Diego Gas and Electric rate schedules power factor cost penalties are imposed if the power factor is less than 90%. HL&P and Virginia Electric and Power Company power factor cost penalties are implied rather than stated as power factor percentages. HL&P bills demand in kVA, which is apparent power. Referring to Figure 2, it can be seen that any

power factor less than 100% results in an increase in the demand charge over that for the actual real power used by the customer. The Virginia Electric and Power Company charges directly for kVAR at a rate of $0.15/kVAR, which is the reactive power associated with power factor less than 100%. Virginia Electric and Power charges for demand at a rate of $12.97947/kW for the first 1,500 kW. By having a separate reactive power charge they are penalizing the customer for any power factor less than 100%, similar to HL&P. Referring to Figure 2, Virginia Electric and Power charges their customers for both the power to do useful work in the plant (real power) and for the reactive power that does no useful work which is associated with power factor less than 100%.

POWER FACTOR CORRECTION

The goal of power factor correction is to reduce the angle Θ between the real and apparent power (see Figure 2). Since the real power required to do useful work does not change, then only apparent power can be changed. This is normally done by adding capacitors to an AC circuit.

Capacitors counteract the effect of inductive circuit components. They alternately draw power from the circuit and then release it back to the circuit, out of phase with inductive circuit components. The two devices, capacitors and inductors, pass the reactive current back and forth.

Power factor correction capacitors are rated in kVAR or kVAC (kilovolt-amperes-capacitance), which subtract directly from a circuit's inductive kVAR. An illustration of adding capacitance to an inductive circuit is provided in Figure 3, where the capacitors reduce the reactive power.

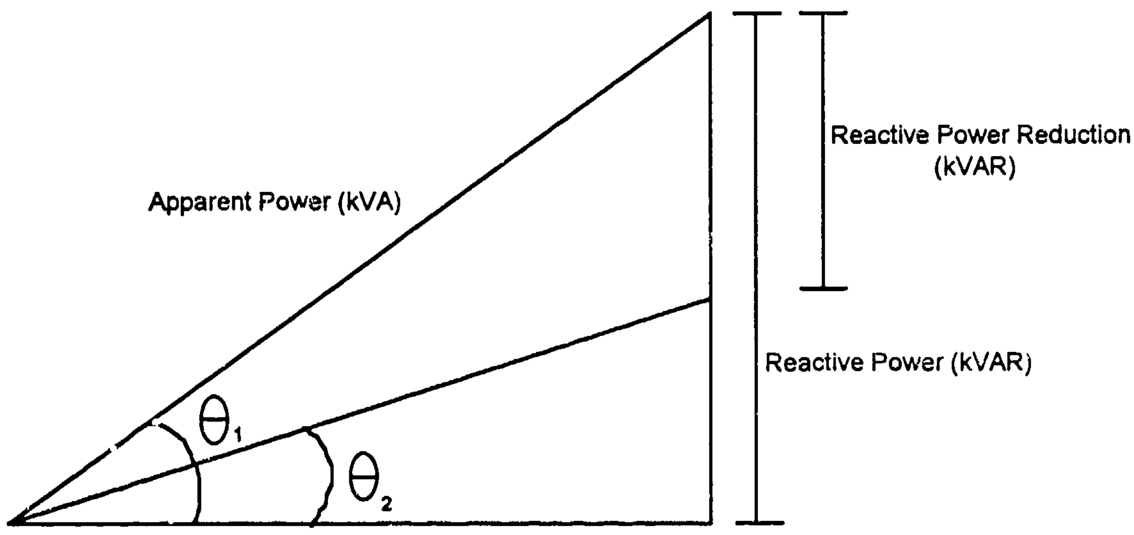

FIGURE 3
Power Factor Correction

By adding the capacitors, apparent power (kVA) will be reduced and the ratio of kW/kVA will be closer to 1.0 (e.g., moving from Θ_1 to Θ_2). It would be desirable to make the power factor equal to 1.0, but typically 0.95 is the best that can be expected for a reasonable cost (Turner 1992).

Power factor correction capacitors can be added at different points in the electrical system. One is at the individual piece of equipment. Another is at groups of equipment, such as in a metal shop where the capacitance would be added to the electrical feed to all lathes. The last point to add capacitance is at the incoming electrical feed to the facility.

Placing the capacitors in the right location is ve important (SMACNA 1984). Advantages to placing the capacitors at the individual piece of equipment are:

- Capacitors increase load capability of the distribution system.

- Capacitors can be switched with the equipment, thus no additional switching or automatic capacitance is needed.
- Better voltage regulation because the capacitor use will follow the load.
- Capacitor sizing is easier.
- Capacitors are installed on the equipment and can be easily moved with the equipment.

The disadvantages of having the capacitance on the individual piece of equipment are:

- Small capacitors cost more per kVAR than larger units. The economic breakpoint for individual correction is generally about 10 hp.

If the capacitors service groups of equipment, the advantages are:

- Increased load capabilities of the electrical service.
- Reduced costs relative to individual correction.
- Reduced installation costs relative to individual correction.

The disadvantages to group correction are:

- Switching or automatic capacitance may be needed to control the capacitance used.

When the capacitance is added to the incoming facility electrical feed, the advantages are:

- Lower material costs.

but the major disadvantages are:

- Switching or automatic capacitance will be needed to control the amount of capacitance used.

- This installation does not improve the load capabilities of the electrical distribution system, as compared to adding capacitance to the individual or groups of equipment.

Other benefits of increasing the power factor are reducing the current drawn by the electrical motors, free up generating capacity for the utility, and in general reducing utility costs for the customer (Turner 1992).

CHAPTER III

SIMPLE TECHNIQUES FOR ACHIEVING SAVINGS

Over time a few simple techniques have been identified which generally result in savings on some of the rate schedule cost features which have been previously discussed. This section will discuss some of the more common savings techniques and how effective they have been for the IAC.

LOWERING DEMAND

To lower the demand that a facility is experiencing, two major options should be considered. The first is to simply shut equipment off during peak demand times, if it is not required for the present operation. The second is to have some scheme of replacing equipment with more efficient equipment. A review of the data compiled by Eggebrecht (1994) in his Master's major report for the IAC gives a listing of the ECO's that were recommended for 200 audits.

The first option of shutting equipment off is recommended about 11% of the time during audits of facilities done by the IAC (Eggebrecht 1994). This ranks it as fifth of the top 25 recommended ECO's, with 66 occurrences since 1986. Typically, the equipment recommended for shut off is small equipment, such as welders, lights, and fans. However, sometimes the equipment is larger, such as air-conditioning units or large furnaces. The savings for equipment shut off can frequently be achieved by a technique as simple as employee education. Implementation costs are relatively small, or zero, when suitable switch gear already exists.

The second option of replacing equipment with more efficient types is recommended approximately 32% of the time during IAC audits. Some of the

most common recommendations are to install higher efficiency lighting fixtures and using energy efficient motors. The typical savings for these two ECO's average $1,155 and $3,728, per year respectively. The simple payback average is approximately 1.6 years.

Other demand reducing practices are to improve lubrication practices (e.g., synthetic lubricants), and power factor correction projects.

All of the above recommendations have simple payback periods in the two to four year range, but surprisingly power factor correction averages a simple payback of 1.7 years (Eggebrecht 1994). Power factor correction projects also normally have large cost savings, averaging $11,813 per year for the small and medium-sized plants (less than $75 million in gross annual sales and less than 500 employees) audited by the IAC.

DEMAND LEVELING

Demand leveling is another option for lowering the facility's peak demand. This can be accomplished by extending the hours worked during the day, increasing the number of shifts operated at the facility, or staggering equipment use over the work day.

A simple example for staggering equipment use or demand leveling would be a process which requires two machines for production, each with a 100 hp motor, during a normal eight-hour shift, attended by one or more workers. If this process was done during two eight-hour shifts (16 hours total), using only one 100 hp motor, the production would theoretically remain the same but the electrical demand would be cut in half.

Demand management ECO's were recommended at least 34 times during audits of facilities by the IAC since 1986 (Eggebrecht 1994). This equates to a 3% recommendation rate.

For changes in the shift schedule to become a reality, the management of the facility requires significant cost savings. During audits conducted by the IAC shift scheduling has been recommended several times, but it is normally not implemented because the cost savings are low compared to the salary, wages, and overhead required to man an extra operating shift.

Other demand leveling techniques include using programmable controllers for thermostats, timers and motion sensors on little-used lighting circuits, or energy management control systems (EMCS). With the increasing use of electronic control circuits for electrical driven machinery, an EMCS is a reasonable solution to decreasing the peak demand and performing demand leveling. There are many contractors who can install and train plant personnel on the use of energy management control systems.

CAPACITANCE

Poor power factor can cost a facility many thousands of dollars over time. This is also a problem from the standpoint of increasing the utilities' load and reducing their capacity. When a facility realizes that the power factor is low, through an audit or other means, the most common way to correct the problem is to install capacitance in the circuit.

Of 200 audits performed by the IAC at Texas A&M University, installing power factor correction was rated as number 11 of the top 25 recommended ECO's, and was implemented 57% of the time it was recommended. The average savings was $11,813 per year, and the implementation cost averaged $19,115. This provided an average simple payback of 1.7 years (Eggebrecht 1994).

Typically the recommendation was to provide the capacitance bank at the incoming electrical feed to the facility. However, if the facility had large electric

motors, usually greater than 10 hp, capacitance could be added to the motor circuits. One advantage of adding the capacitance to the individual piece of equipment is that it could be moved with the equipment, if needed. Other advantages and disadvantages were provided in the previous chapter.

If a facility is experiencing a growth period, attaching the capacitance to the individual pieces of equipment is the more preferred method (Laham 1992). However, the cost of smaller capacitors is more per kVAR than with larger units. Therefore, the management of the facility should request the advice of an electrical engineer prior to making the final decision on where the capacitance is to be added.

CHAPTER 4

EDUCATION OF PERSONNEL ABOUT MAJOR RATE STRUCTURE FEATURES

NEED

As mentioned earlier in this study, frequently facility representatives do not fully understand demand, block extenders, and power factor. This results in the staff and students from the IAC attempting to present the information to them in a relatively short period of time during their one-day visit. Often more instruction than the one-day IAC visit is needed to adequately explain demand, block extenders and power factor for the plant personnel to gain a full understanding of how they can influence their monthly utility bills.

OPPORTUNITIES

Two current methods of instructing plant personnel are available. The IAC currently makes use of Energy Cost Analysis (ECA's) presentation to plant personnel when arriving for the one-day audit. As noted in a previous report (Eggebrecht 1994), the ECA does provide some assistance but experience in audits has shown this frequently is not adequate because of the time constraint to present the information.

The video, which has been produced as part of this study, is another method of instruction available. Current plans are to use the video at plants where audio-visual equipment is available. If response is positive to the video, audio-visual equipment may be purchased for use during audits when such equipment can not be made available by the plant.

This video is relatively short, less than fifteen-minutes, and covers the basics on demand, block extenders, and power factor. Therefore, the video can be shown before the ECA is presented and then any weak areas will be discussed during the ECA presentation. The ECA will provide more specific information applicable to the particular plant being considered.

Also, by having copies of the video available, plant personnel will have the option of requesting a copy for further review after the audit has been completed. This will assist in clearing up weak areas on demand, block expanders, and power factor, without IAC personnel making another visit (which is not currently done).

By presenting both the video and ECA, the hope is that two different presentation media will assist in instructing plant personnel more thoroughly. Normally, using different instructional media provides better overall retention of the subject matter (U.S. Department of Education 1994).

VIDEO PRODUCTION

Though the video is relatively short, considerable time and expense were required for the final production. A general flow path to obtain the final production is presented below.

The first step in the production process was to select a reasonably priced producer. Since no prior experience was available, a telephone search was made and a video producer was chosen after discussing budget and general expectations. Subsequently, a meeting between the student and the producer established certain requirements. The main requirement for the student was to provide a script and the graphics for the video.

The script, as provided in Appendix C, took approximately a month to compose, including rewrites, edits, and graphics. The desire was to limit the

final video production at ten to fifteen-minutes. This time limit was chosen due to constraints on audit visits and attention span for the information on the video is better for short durations.

Once the script was completed, rehearsals and 'dry runs' were conducted for personnel familiar with the information. This provided feedback on speed of presentation and areas of the script to stress.

Finally the video 'shoot' day arrived. The many re-takes, close-ups and general video shots took approximately six hours. A general photography studio was used for backdrops and lighting due to cost constraints.

After the filming day, the video production company edited and provided on-screen graphics at points of interest within the video production. Since the production company did not have the proper equipment to do the editing and graphics, the video was taken to another location for the editing and graphics. This portion of the video production took approximately three or four weeks.

Therefore, the total time to produce the video, once the decision was made to use video media, was approximately two to three months. If all the editing, on-screen graphics and other equipment had been owned and operated by one production company the time may have been shortened to two months or less.

SUMMARY

Utility demand and energy rate schedules can vary significantly across the nation, and understanding major components of the various rates is important. Interest is often focused on the demand, energy, and power factor requirements of the particular rate schedule for savings for the facility involved.

Electrical demand and energy savings potentials are abundant. Some are very simple, such as shutting equipment off during lunch and breaks. Several of the books recommended in the annotated bibliography are excellent sources to find methods for demand and energy savings.

Continued education of personnel at large commercial and industrial facilities is required, including the military community. The video, which was produced as part of this study, is a new method of instruction which may prove very useful. Continued improvements on the video production presented here could include a more professional presentation with better and higher technology equipment being used.

REFERENCES

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Eitel, R., 1993, Personal communication with Utilities Director, Norfolk Public Works Center regarding Virginia Electric and Power Company rate structure, Norfolk, VA., September, 1993.

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Laham, G.N., 1992, Lowering Costs Through Power Factor Improvement, *Consulting-Specifying Engineer,* October 1992. pp. 28-34.

SMACNA, 1984. *Energy Conservation Guidelines.* Sheet Metal and Air-Conditioning Contractors' National Association, Inc., Tysons Corner, Vienna, VA. 22180. pp. 57-59.

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Thumman, A. and Mehta, D. P., 1991, *Handbook of Energy Engineering, 2nd Edition,* Lilburn, Ga. Fairmont Press, Chapters 3 and 4.

Turner, W. C., 1993, *Energy Management Handbook, 2nd Edition,* Lilburn, Ga. Fairmont Press, pp. 253,597, Chapters 3, 12, and Appendix III.

U.S. Department of Education, 1994, *Mathematics, Science, and Technology Education Programs that Work,* Office of Educational Research and Improvement, Washington, D.C, pp. 9-11.

APPENDIX A

Annotated Bibliography

1. I. Mechler, Milton, ed. Retrofitting of Commercial, Institutional, and Industrial Buildings for Energy Conservation. New York: Van Nostrand Reinhold Company, Inc., 1984.

This book has an easy-to-use format that details step-by-step procedures to initiate an energy efficiency project, from performing an audit, and designing, implementing, and evaluation of the resultant project.

2. Thumann, Albert. Plant Engineer and Managers Guide to Energy Conservation, 5th ed. Lilburn, GA: The Fairmont Press, Inc., 1991.

This guide provides information on life cycle costing, electrical and HVAC system optimization, methods to reduce building energy loss, and a very practical guide to establishing an energy conservation (efficiency) maintenance program. It also provides a list of microcomputer programs for energy analysis that would be of great benefit to energy managers.

3. Turner, Wayne C. Energy Management Handbook, 2 ed. Lilburn, GA: The Fairmont Press, Inc., 1993.

This reference manual provides methods and instrument listing to perform energy audits of facilities. Also provides typical energy conservation opportunities for industrial, commercial, and businesses including suggested methods of maximizing energy efficiency. Includes information on cogeneration, energy management control systems (EMCS), alternative fuels, and thermal energy storage.

4. United States Navy. DoD Energy Manager's Handbook (Draft), Vol. 1. Washington, D.C.: Government Printing Office, 1993.

This handbook provides both experienced and inexperienced energy managers with information on implementing an energy management program to meet DoD goals for energy conservation.

APPENDIX B

Rate Schedules

SCHEDULE MS
FEDERAL GOVERNMENT INSTALLATIONS

I. APPLICABILITY

This schedule is applicable to any Federal Government installation contracting for 1500 kW or more of alternating current electricity. Such installation served under this schedule may change to service under the Company's Schedule No. 6 - Large General Service, and vice versa, effective with the meter reading date immediately preceding the receipt by the Company of the Government's written request for such change, if (1) the initial term of the applicable schedule has been satisfied; or (2) a change is made in the rate for service under either schedule. However, when an installation makes such change, the installation must remain on the then-selected schedule for at least one year after the change is made, regardless of changes in either rate schedule during such one-year period, other contract provisions to the contrary notwithstanding.

II. SERVICE AVAILABLE

The Company will supply the equipment necessary and will deliver to the Customer at a delivery point mutually satisfactory to the Customer and the Company, 60 hertz alternating current electricity of the phase and Company standard nominal voltage desired by the Customer at said delivery point, provided electricity of the phase and voltage desired by the Customer is available generally in the area in which electricity is desired.

III. 30-DAY RATE

REVISED 4/93

A. KW Demand Charge
First 1500 kW of Demand or Less ~~$19,354.64~~ 19,469.21
Additional kW of Demand @ $ ~~12.54~~ per kW 12.61638

B. Plus rkVA Demand Charge
All rkVA of Demand @ $ 0.15 per rkVA

C. Plus Energy Charge
All kWh @ $ 1.968¢ per kWh

D. Fuel Factor

1 Prior to April 91 • .159 kWH
April 91 • .00067 kWH
April 92 •.000330 kWH → ok per Jim 4/20/92
April 93 • .00202 kWH

(Continued)

Superseding Schedule Adopted 05-17-91
Effective 03-16-91. This Schedule Adopted:
(Equivalent to Proposed Schedule NC-RS from FERC Docket No. ER91-562-000) Effective:

SCHEDULE MS
FEDERAL GOVERNMENT INSTALLATIONS

(Continued)

III. 30-DAY RATE (Continued)

D. Annual Fuel Adjustment Factor

1. The kilowatthours in each customer's bill for the current billing month shall be multiplied by an annual fuel adjustment factor which shall be equal to the sum of:

(a) the estimated current-period fuel adjustment factor, and

(b) the prior-period deferral adjustment factor.

2. The estimated current-period fuel adjustment factor to become effective with the April billing month of each year shall be based on the total estimated system fuel expenses allocable to Schedule MS and Schedule MS kilowatthour sales for the 12-month period beginning in April of each year, and shall be calculated by the fuel adjustment factor formula shown below rounded to the nearest thousandth of a cent.

3. The prior-period deferral adjustment factor to become effective with the April billing month of each year shall be based on the difference between the total fuel expenses (using the criteria outlined (a) through (c) of paragraph 7. below) allocable to Schedule MS and the total fuel recoveries by Schedule MS customers for the 12 months prior to April of each year, divided by the estimated Schedule MS kilowatthour sales for the 12-month period beginning with April of each year (6 months where a semi-annual change is made pursuant to paragraph 5. below). The prior-period deferral adjustment factor will be adjusted for taxes.

(Continued)

SCHEDULE MS
FEDERAL GOVERNMENT INSTALLATIONS

(Continued)

III. 30-DAY RATE (Continued)

4. The intent of the annual fuel adjustment factor is to recover all fuel expenses allocable to Schedule MS customers. To the extent the amount recovered from Schedule MS customers through annual fuel adjustment factors and the fuel component of the base rate exceeds the cost of fuel allocable to Schedule MS for the same time period, this over-recovery shall be a credit in the calculation of the prior-period deferral adjustment factor for the 12-month period beginning with the next April. To the extent the amount recovered from Schedule MS customers through the annual fuel adjustment factor and the fuel component of tho base rate is less than the cost of fuel allocable to Schedule MS for the same time period, this under-recovery shall be a charge in the calculation of the prior-period deferral adjustment factor for the 12-month period beginning with the next April.

5. The annual fuel adjustment factor shall be reviewed on a semi-annual basis to determine if any change is required. The current and prior period portions of the fuel adjustment factor will be reviewed individually, and a change to one or both may be made. The adjustment may be deferred until the end of the 12-month period, provided the net difference between the Company's actual and estimated under-recovery at the end of the 12-month period is no greater than seven and one-half per centum of actual and estimated fuel expenses or the net difference between the actual and estimated over-recovery at the end of the 12-month period is no greater than five per centum of actual and estimated fuel expenses.

(Continued)

SCHEDULE MS
FEDERAL GOVERNMENT INSTALLATIONS

(Continued)

III. 30-DAY RATE (Continued)

6. Fuel adjustment factor formula:

$$F = [\frac{E_1 + E_2}{S} - B]\ (T)\ (100)$$

Where:

F = Estimated fuel adjustment factor in cents per kilowatthour.

E_1 = Estimated North Anna fuel expenses plus estimated Old Dominion Electric Cooperative Buyback fuel expenses allocated to Schedule MS Customers.

E_2 = Estimated total fuel expenses less estimated North Anna fuel expenses and Old Dominion Electric Cooperative Buyback fuel expenses allocated to Schedule MS Customers.

S = Estimated total Schedule MS kilowatthour sales for the 12-month period beginning with April each year.

B = Base cost of fuel per kWh = $0.01500.

T = Adjustment for state and local taxes measured by gross receipts: 100% divided by (100% minus applicable gross receipts tax rate).

(Continued)

SCHEDULE MS
FEDERAL GOVERNMENT INSTALLATIONS

(Continued)

III. 30-DAY RATE (Continued)

7. The estimated fuel expenses allocable to the Schedule MS Customers for the 12-month period beginning April of each year, shall be determined as follows:

(a) Fossil and nuclear fuel consumed in the Utility's own plants, and the Utility's share of fossil and nuclear fuel consumed in jointly owned or leased plants.

The cost of fossil fuels shall be those items initially charged to account 151 and cleared to accounts 501, 518, and 547 on the basis of fuel used. In those instances where a fuel stock account (151) is not maintained, e.g., gas for combustion turbines, the amount shall be based on the cost of fuel consumed and entered in account 547.

The cost of nuclear fuel shall be the amount contained in account 518 except that if account 518 also contains any expense for fossil fuel which has already been included in the cost of fossil fuel, it shall be deducted from this account.

<u>Plus</u>

(b) The following purchased power costs:

(i) The fuel cost component of any purchased power transaction.

<u>or</u>

(Continued)

SCHEDULE MS
FEDERAL GOVERNMENT INSTALLATIONS

(Continued)

III. 30-DAY RATE (Continued)

(ii) The total en / charges associated with economic purchases if the energy charges are less than the Company's total avoided variable costs during the purchase period.

or

(iii) The total expense associated with purchased power of less than twelve months duration if the total cost of the purchase is less than the Company's total avoided variable costs and if the purpose of the purchase was solely to displace higher cost generation. Purchases made to solely displace higher cost generation exclude reliability purchases. A purchase shall be deemed for reliability where the Company's system reserve criterion is not met. Such criterion is as follows:

<u>Operating Reserve</u> (consisting of the largest generating unit plus regulating margin plus load forecast margin)

<u>Minus</u>

<u>75% of Emergency Contract Capacity</u>

<u>Equals</u>

<u>Spinning Reserve Requirement</u>

(iv) Energy receipts that do not involve money payments such as Diversity Energy and pay-back of Storage Energy are not defined as Purchased or Interchanged Power relative to the Fuel Clause.

(Continued)

SCHEDULE MS
FEDERAL GOVERNMENT INSTALLATIONS

(Continued)

III. 30-DAY RATE (Continued)

<u>Minus</u>

(c) The cost of fossil and nuclear fuel recovered through inter-system sales including the fuel costs related to economy energy sales and other energy sold on an economic dispatch basis.

Energy deliveries that do not involve billing transactions such as Diversity Energy and pay-back of Storage Energy are not defined as sales relative to the Fuel Clause.

E. The charges in Paragraph III. above to Federal Government customers served under this schedule shall be increased or decreased appropriately by any applicable riders.

IV. DISCOUNTS

Discounts will apply only to charges under Paragraphs III.A. and C. for services with delivery voltages of 69 kV or higher.

A. KW Demand Discount
All KW of Demand @ $0.66 per kW Discount

B. Energy Charge Discount
Energy Charge @ 2.0% Discount

V. MINIMUM CHARGE

The minimum charge shall be such as may be contracted for but not less than the sum of the charges in the 30-Day Rate Paragraph III.A. and B. including applicable discounts in Paragraph IV.A. This includes no allowances of energy, and all energy used shall be paid for in addition at the above rates. Such minimum charge shall be increased in the amount of the applicable fuel adjustment under Paragraph III.D.

(Continued)

SCHEDULE MS
FEDERAL GOVERNMENT INSTALLATIONS

(Continued)

VI. OTHER PROVISIONS

A. Determination of kW Demand

The kW of demand billed under Paragraph III.A. shall be the highest of:

1. The highest average kW measured at this location in any 30-minute interval during the on-peak hours of 7:00 a.m. to 10:00 p.m., Mondays through Fridays, plus 30% of the excess of this amount determined in a similar manner during any other period during the current billing month, or

2. 90% of the highest kW of demand at this location as determined by Subparagraph VI.A.1., above during the billing months of June through September of the preceding eleven billing months, or

3. 50% of the kW of demand contracted for under Paragraph VII., or

4. 1500 kW.

B. Determination of rkVA Demand

The rkVA of demand billed shall be the highest average rkVA measured in any 30-minute interval during the current billing month.

C. Meter Reading and Billing

When the actual number of days between meter readings is more or less than 30 days, the kW Demand Charge, the rkVA Demand Charge, the charge per kW of contracted demand in Paragraph VIII.C., and the minimum charge of the 30-day rate will each be multiplied by the actual number of days in the billing period and divided by 30.

(Continued)

SCHEDULE MS
FEDERAL GOVERNMENT INSTALLATIONS

(Continued)

VI. OTHER PROVISIONS (Continued)

D. Late Payment Charge

A late payment charge of one percent (1%) per month will be applied on all amounts that remain unpaid on the Company's books on the next billing date.

VII. DETERMINATION OF CONTRACT DEMAND

The contract demand under this schedule shall be the maximum number of kW which the Company is to supply. Contract demands may be changed by mutual agreement as to amount of change and term of agreement.

VIII. BREAKDOWN, RELAY OR PARALLEL OPERATION SERVICE

Breakdown, relay or parallel operation service may be contracted for under this schedule under the following conditions:

A. Suitable relays and protective apparatus shall be furnished, installed, and maintained at the Customer's expense in accordance with specifications furnished by the Company. The relays and protective equipment shall be subject, at all reasonable times, to inspection by the Company's authorized representative.

B. The contract demand to be billed under this Paragraph VIII. shall be the maximum number of kW which the Company is to supply. Contract demands may be changed by mutual agreement as to the amount of change and term of agreement. In case the maximum measured kW demand exceeds the contract demand, the measured demand becomes the contract demand for that month and for the next succeeding eleven months.

C. When breakdown, relay or parallel operation service is furnished, the 30-Day Minimum Charge for electricity supplied under this schedule shall not be less than $12.54 per kW of demand contracted for under Paragraph VIII.B. plus any positive fuel adjustment charge under Paragraph III.D.

(Continued)

SCHEDULE MS
FEDERAL GOVERNMENT INSTALLATIONS

(Continued)

IX. SCHEDULE TERMINATION, MODIFICATION OR REVISION

Whenever the Federal Energy Regulatory Commission shall permit a change in the rates set forth in the Company's Schedule NC-RS, Resale Service to the Town of Enfield, North Carolina and the Town of Windsor, North Carolina. (Schedule RS renamed in FERC Docket No. ER90-540-000) - to take effect, this rate schedule shall on the same effective date be modified so as to produce from the Federal Government customers served hereunder the same rate of return as the rates thus permitted to become effective for Schedule NC-RS customers, utilizing for that determination the same ratemaking methodology and test period as used in determining the NC-RS rates. Pending final decision by the FERC, the Federal Government would pay a rate as initially proposed by the Company after the suspension period, if any, subject to refund after final decision of any excess payments plus interest at the rate as authorized by the FERC. This method of determining a rate for the Federal Government customers will continue in effect indefinitely; provided, however, that either party may terminate this method of rate determination by giving six months' notice. Should such a termination occur, the parties, if appropriate, would negotiate a new rate in good faith.

X. TERM OF CONTRACT

The term of contract for the purchase of electricity under this schedule shall be such as may be mutually agreed upon, but for not less than one year.

(Continued)

Superseding Schedule Adopted 05-17-91 Effective 03-16-91. This Schedule Adopted: (Equivalent to Proposed Schedule NC-RS from FERC Docket No. ER91-562-000) Effective:

VIRGINIA ELECTRIC AND POWER COMPANY
7DEB662.sch

RIDER OPEB
FOR SERVICE TO
FEDERAL GOVERNMENT INSTALLATIONS
UNDER SCHEDULE MS

For each billing month, the kW demand charge stated in Paragraph III.A. of Schedule MS shall be increased by $.07638/kW.

This Rider shall become effective on January 1, 1993, and is designed to recover costs associated with funding of Other Post Employment Benefits (OPEB) on an accrual basis in accordance with the Financial Accounting Standard No. 106 (SFAS No. 106), "Employer's Accounting for Postretirement Benefits Other than Pensions," released December 1990, in excess of the amounts, calculated on a pay-as-you-go level, that are included in rates effective March 1, 1992. This Rider shall remain in effect until such time it is withdrawn or replaced by the Company.

This Schedule Adopted: 03-01-92
Effective: 03-01-92, Subject to approval of wholesale customer settlement rates in FERC Docket No. ER91-562-000.

RATE 6L. LARGE GENERAL SERVICE

* The rate changes scheduled to become effective on March 15, 1992 and March 15, 1993 stayed by Order of the Supreme Court in No. 71602, et. al., on February 3, 1992. The charges in effect on March 20, 1991 shall remain in effect until the stay is lifted or superseding rates become effective.

Applicability.

This rate is applicable to (1) any commercial, industrial, or governmental customer with a Maximum Demand of 1,000 kilowatts or more in three of the 12 months preceding the billing month, (2) successors to customers served under these charges immediately prior to the date of succession whose estimated Maximum Demands meet the demand requirements in clause (1) above, (3) new customers whose estimated Maximum Demands meet the demand requirements in clause (1) above, and (4) any customer previously billed hereunder pursuant to clauses (1) or (2), except as otherwise provided below.

If a customer at one time was served pursuant to (1) above on Large General Service—Time of Day and has a Maximum Demand which has not exceeded 800 kilowatts in any month of the 16 month period preceding the billing month, such customer may elect, in written application to the Company, to be served on Rate 6, General Service. Rate 6L, Large General Service—Time of Day, shall not again be applicable until such customer qualifies for such rate under clause (1) above.

The Large General Service—Heating with Light charges shall be applicable only to customers or their successors with electric space heating taking service under the Heating with Light provisions of Rider 25 prior to November 23, 1977.

A Large General Service—Heating with Light customer will be allowed to take Large General Service—Time of Day service upon written application to the Company. Once changed to Large General Service—Time of Day service, those customers or their successors will not be allowed to return to Large General Service—Heating with Light.

Charges.

Large General Service—Time of Day.
Monthly Customer Charge.

	Period 1 March 15, 1991 Through March 14, 1992	Period 2 March 15, 1992 Through March 14, 1993	Period 3 March 15, 1993 Through March 14, 1994	Period 4 March 15, 1994 and After
The Monthly Customer Charge shall be:	$528.16	$549.02	$570.71	$552.26

Demand Charge.
Charge per kilowatt for all kilowatts of Maximum Demand for the month:

	Period 1	Period 2	Period 3	Period 4
Summer Months				
For the first 10,000 kilowatts	$16.41	$17.05	$17.72	$17.15
For all over 10,000 kilowatts	$ 7.12	$ 7.40	$ 7.68	$ 7.43
All Other Months				
For the first 10,000 kilowatts	$12.83	$13.34	$13.87	$13.42
For all over 10,000 kilowatts	$ 5.50	$ 5.72	$ 5.95	$ 5.76

For the purposes hereof, the Summer Months shall be the customer's first monthly billing period with an ending meter reading date on or after June 15 and the three succeeding monthly billing periods.

Energy Charge.
Charge per kilowatthour for kilowatthours supplied in the month:

	Period 1	Period 2	Period 3	Period 4
during Peak Periods	5.490¢	5.707¢	5.933¢	5.741¢
during Off-Peak Periods	2.369¢	2.463¢	2.560¢	2.477¢

The adjustment charge or credit provided for in Rider 20 shall apply to all kilowatthours supplied in the month.

Large General Service—Heating with Light.
Monthly Customer Charge.

	Period 1	Period 2	Period 3	Period 4
The Monthly Customer Charge shall be:	$528.16	$549.02	$570.71	$552.26

(Continued on Sheet No. 29)

RATE 6L. LARGE GENERAL SERVICE

(Continued from Sheet No. 28)

* The rate changes scheduled to become effective on March 15, 1992 and March 15, 1993 stayed by Order of the Supreme Court in No. 71602, et. al. on February 3, 1992. The charges in effect on March 20, 1991 shall remain in effect until the stay is lifted or superseding rates become effective.

Demand Charge.
Charge per kilowatt for all kilowatts of Maximum Demand for the month:

	Period 1	Period 2	Period 3	Period 4
For Summer Months	$16.41	$17.05	$17.72	$17.15
For All Other Months	$12.83	$13.34	$13.87	$13.42

Energy Charge.
Charge per kilowatthour for kilowatthours supplied in the month:

	Period 1	Period 2	Period 3	Period 4
For the first 30,000 kilowatthours	4.196¢	4.364¢	4.536¢	4.389¢
For the next 470,000 kilowatthours	3.163¢	3.287¢	3.416¢	3.306¢
For all over 500,000 kilowatthours3.115¢	3.236¢	3.362¢	3.253¢	

The adjustment charge or credit provided for in Rider 20 shall apply to all kilowatthours supplied in the month.

Late Payment Charge.
The late payment charge provided for in the Terms and Conditions of this Schedule of Rates shall be applicable to all charges under this rate.

Minimum Charge.
The minimum monthly charge shall be the Monthly Customer Charge.

Maximum Charge.
The average cost of electricity hereunder in any month, exclusive of the Monthly Customer Charge, shall not exceed the sum of the Maximum Charge and the Rider 20 adjustment per kilowatthour provided, however, that such guaranteed charge shall not operate to reduce the customer's bill to an amount less than the Minimum Charge.

	Period 1	Period 2	Period 3	Period 4
The Maximum Charge shall be:	21.107¢	21.942¢	22.810¢	22.072¢

Maximum Demand.
Except as noted in the paragraph below, the Maximum Demand in any month shall be the highest 30-minute demand established during the Peak Periods in such month except that, for customers with 30-minute demands exceeding 1,500 kilowatts in three of the 12 months preceding the billing month, the Maximum Demand shall be the average of the three highest 30-minute demands established during the Peak Periods in such month, not more than one such demand to be selected from any one day.

For customers taking service under Large General Service—Heating with Light provision of this rate the Maximum Demand shall be the highest 30-minute demand established at any time during such month except that, for customers with 30-minute demands exceeding 1,500 kilowatts in three of the 12 months preceding the billing month, the Maximum Demand shall be the average of the three highest demands established during the month, not more than one such demand to be selected from any one day.

Measurement of Demand and Kilowatthours Supplied.
Where two or more metering installations are provided on the customer's premises, the demand in any 30-minute period shall be determined by adding together the separate demands at each metering installation during such 30-minute period except that (a) in case the demand at any metering installation is registered by an indicating or cumulative demand meter, the demand at such installation in each 30-minute period of any month shall be assumed to be the same as the highest demand in any 30-minute period of such month, and (b) the demand at any installation may be assumed to be 75 percent of the connected load if such connected load is 2 kilowatts or less, and such demand is to be added to a metered demand. Where there are two or more watthour metering installations, the kilowatthours supplied shall be determined by adding together the kilowatthours metered at each installation, provided that where the kilowatthours at any such installation exceed 5,500 in the billing month and are not metered in such a manner as to permit determination of the hours during which they were delivered, for purposes of applying the time of day provisions of this rate, such kilowatthours shall be considered to have been delivered in Peak Periods. If the energy use at such installation is 5,500 kilowatthours or less in the billing month, the following charge per kilowatthour shall apply to such kilowatthours:

Period 1	Period 2	Period 3	Period 4
3.661¢	3.806¢	3.956¢	3.828¢

The Maximum Demands and kilowatthours supplied for two or more premises will not be combined for billing purposes hereunder.

(Continued on Sheet No. 30)

RATE 6L. LARGE GENERAL SERVICE

(Continued from Sheet No. 29)

Upon request, the Company will provide unmetered service for connected loads not exceeding two kilowatts where operation of the customer's equipment is continuous or is regularly scheduled on an annual basis. For the purposes of billing in such cases, the monthly kilowatthours shall be determined by multiplying the rated wattage (based upon nameplate or other appropriate data) of connected loads by one-twelfth of the annual hours of operation and dividing by 1,000. All kilowatthours delivered to an unmetered point of supply shall be considered to have been delivered during Peak Periods.

Service Facilities.

A standard installation furnished by the Company hereunder shall be determined by the provisions of the Company's Rider 6 except that the facilities so provided as standard shall be adequate only to supply service to a load equal to the maximum 30-minute demand of the customer established during the peak period. If larger facilities are required to serve the excess of the off-peak demand over the peak demand, the customer shall pay, as optional facilities in accordance with the Company's Rider 6, the cost of any facilities so required. However, no optional facilities charges shall apply to facilities existing and in place at the time the customer qualifies for service hereunder.

Adjustment of Demands.

In case the customer, as a result of seasonal or vacation variations in load, has an abrupt decrease of at least 50% in his Maximum Demand during the months of June through September, he will be entitled to the proration of demand charges in the billing period in which such decrease occurs, and if, in the same calendar year, he has a subsequent abrupt increase of at least 100% in Maximum Demand during such months, he will be entitled to the proration of demand charges in the billing period in which such increase occurs, provided that (1) a period of reduced demand continues for at least seven consecutive days immediately following the demand reduction for which proration is sought, and for at least seven consecutive days immediately preceding the demand increase for which proration is sought, (2) demands registered by an indicating or cumulative demand meter shall not be subject to such proration, (3) such proration will be granted only upon written request by the customer stipulating the date of such decrease or increase and received by the Company in advance of such date, and (4) that proration will be granted for only one such decrease and subsequent increase in each calendar year.

Term of Contract.

For customers first receiving service hereunder, the initial term of contract shall be 24 months. Upon expiration of the initial or any renewal term of contract hereunder, the customer's contract shall be automatically renewed for a period of 12 months. For customers receiving service under Rate 6 immediately prior to service hereunder, the unexpired term of contract under Rate 6 shall be the unexpired term hereunder.

A new contract, with an initial term of 24 months, shall be required whenever the Company is called upon to provide additional or different facilities to serve a demand greater than that specified in the Customer's then effective contract, and the term of such new contract shall commence at the beginning of the month next following the date when the facilities installed to serve the increased demand become available for service.

The customer shall have the right to terminate his contract and discontinue service from the Company at any time on 30 days' written notice to the Company; provided, however, that in the event of such termination all amounts due the Company shall forthwith be paid.

General.

Nothing in this rate shall be deemed to preclude a residential occupancy on the customer's property from being served as a separate customer on a residential rate.

Peak periods, for purposes hereof, shall be the hours of 9:00 a.m. to 10:00 p.m. on Monday through Friday, except on days on which the following holidays are generally observed: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, Christmas Day and, if one of the foregoing holidays occurs on a Tuesday or Thursday, the immediately preceding Monday or immediately following Friday, respectively. Off-peak periods shall be all other hours.

The Schedule of which this rate is a part includes certain general Terms and Conditions and Riders. Service hereunder is subject to these Terms and Conditions and the Riders applicable to this rate.

RIDER 11

SERVICE AT 69,000 VOLTS OR HIGHER

Applicable to Rates 6, 6L and 18

* **Service at 69,000 Volts and Above.**

Where the Company line(s) enters the customer's premises at a voltage of 69,000 or higher, the customer shall be allowed a credit of 10.050¢ per kilowatt on that portion of the demand used for billing each month under Rate 6 or 6L which is served at 69,000 volts or higher. However, when applicable to billing under Rate 18, Standby Service, such credit shall be multiplied by the Load Factor Adjustment defined therein.

General.

Except as specified above, all other provisions of the rate shall apply.

RIDER 20

ELECTRIC FUEL ADJUSTMENT CLAUSE

Applicable to all Rates except Rates 23 and 26 and also applicable to Riders 13, 25 and 26

This rider is applicable to all kilowatthours (KWH's) of energy supplied to customers served by the Company under the above designated rates and riders and under individual contracts on file with the Illinois Commerce Commission (Commission) where the charge for such energy is subject to adjustment for increases and decreases in the cost of fuel. **Effective for bills issued for the July, 1990 billing period and after.**

Costs passed through the Electric Fuel Adjustment Clause represent estimates of actual costs to be incurred, with adjustment to actual costs as they become available. The fuel costs used in calculating the Fuel Adjustment Charge or Credit per KWH are the total of allowable fuel and fuel related costs as identifed herein.

The charges for all KWH's of energy supplied to designated customers shall be increased or decreased by a Fuel Adjustment Charge or Credit determined as follows:

$$FAC = \left[\left(\frac{(CF + CPP - CNS) \times 100}{S}\right) - BFC + Ra + Ro + D\right] \times GT$$

where:

FAC = Fuel Adjustment Charge or Credit per KWH: The amount in cents per KWH, rounded to the nearest .001¢, to be charged for each KWH in any monthly billing period. The FAC is subject to adjustment to minimize over/under recoveries of allowable fuel costs by application of the automatic reconciliation factor (Ra) and the ordered reconciliation factor (Ro) as defined herein. The FAC is also subject to adjustment by applicaton of a desulfurization factor (D) to recover certain desulfurization costs as defined herein.

CF = Allowable Cost of Fuel associated with Company owned generating plants: Fuel cost includes the cost of all fossil and nuclear fuel to be consumed in the Company owned plants and/or in plants owned by wholly-owned subsidiaries of the Company and/or the Company's share of fossil and nuclear fuel to be consumed in jointly owned or leased plants during the period for which the FAC is being determined.

CPP = Allowable Energy Cost associated with Purchased Power: Purchased power includes emergency, contract and economy purchases from other electric utilities and from customers served under the Company's Rider 4, Parallel Operation of Customer's Qualifying Generating Facilities. Except for power purchased for economy reasons, only the energy related portion of the charges for power to be purchased during the period for which the FAC is being determined is included. The demand charge portion of the charges for power to be purchased for economy reasons is also included. All other associated charges are specifically excluded. Non-monetary exchanges of power are not included.

CNS = Fuel Costs associated with Sales Not Subject to the Electric Fuel Adjustment Clause: Non-jurisdictional sales include sales for resale, interdepartmental sales, energy furnished without charge and other sales not subject to the Electric Fuel Adjustment Clause. Such fuel costs shall be calculated on the basis of the average fuel costs during the period for which the FAC is being determined except in the case of fuel costs associated with interchange power sales (emergency, contract and economy power sales to other electric utilities) which shall represent the amounts to be recovered with respect to fuel in such sales, ordinarily the incremental cost of such fuel.

(Continued on Sheet No. 83.10)

RIDER 20

ELECTRIC FUEL ADJUSTMENT CLAUSE

(Continued from Sheet No. 83)

S = KWH's subject to FAC estimated to be billed to ultimate consumers during the period for which the FAC is being determined.

BFC = Base Fuel Cost: The base fuel cost is the fuel cost included in the energy charges of the Company's rates. This base cost is equal to 1.178 cents per kilowatthour.

Ra = Automatic Reconciliation Factor: The automatic reconciliation factor shall be calculated based on the over/under recoveries of actual allowable costs at the end of the second month prior to the billing period divided by the KWH's subject to the Electric Fuel Adjustment Clause estimated to be billed to ultimate consumers during the billing period. The automatic reconciliation factor shall be a credit or charge depending on whether there has been an over or under recovery.

Ro = Ordered Reconciliation Factor: The FAC is subject to an ordered reconciliation factor as may be required by the Commission.

D = Desulfurization Factor: The desulfurization factor shall be calculated based on the desulfurization costs as defined herein incurred in the second month prior to the billing period divided by the KWH's subject to the Electric Fuel Adjustment Clause estimated to be billed to ultimate consumers during the billing period.

GT = Gross Receipts Tax Factor: The gross receipts revenue tax factor is calculated in accordance with the following formula:

$$GT = \frac{100}{(100 - t)}$$

where t is the revenue tax rate embodied in the Company's rates. This tax rate is equal to 4.00 percent in the City of Chicago and zero percent outside the City of Chicago.

The billing period is the period beginning with the first billing cycle of the month for which the FAC is being determined and ending with the last billing cycle thereof.

The allowable fuel and fuel related costs (CF), will include the direct cost of fuel delivered at the Company's generating plants. The direct fossil fuel costs are limited to costs entered into fuel expense Accounts #501 and #547 which have been cleared upon consumption from Fuel Stock Account #151, or in the case of gas fuel the amount which is charged directly to Accounts #501 and #547. Costs cleared from Fuel Stock Accounts #152 and #153 are specifically excluded. The cost of fuel used in the generation or production of electric power shall not include transportation costs of coal.

The cost of nuclear fuel will be that as expensed in Account #518, including provisions for storage and disposal of spent nuclear fuel and spent fuel disposal fees with related interest, except that handling costs for nuclear fuel assemblies or any expense for fossil fuel which has already been included in the costs of fossil fuel are specifically excluded.

The costs of fuel consumed associated with test generation shall be included in allowable fuel and fuel related charges to the extent that they are equal to or less than the average fuel costs of the Company's other units operated during the period for which the FAC is being determined. Average fuel costs equal total fuel costs of the Company's generating facilities less the cost of test generation, divided by total net generation less test generation.

Desulfurization costs shall be payments for professional services, licenses, etc., for the implementation and operation of a process for the desulfurization of the flue gas when burning high sulfur coal at any location within the State of Illinois irrespective of the attainment status designation of such location.

The interpretation and application of this rider will be in accordance with all provisions set forth in 83 Illinois Administrative Code Part 425 as ordered by the Commission.

(Continued on Sheet No. 83.20)

RIDER 20

* ELECTRIC FUEL ADJUSTMENT CLAUSE

(Continued from Sheet No. 83.10)

The difference between the amount of the overcharge as provided in the First Interim Order on Remand in Docket 87-0427 et al, dated June 27, 1990, in Section 2 on page 20 and the amounts passed on to customers through the Ro factor shall be reflected in an over/under recovery balance in the rider and shall be charged or credited to all customers subject to this rider in accordance with the provisions under this rider for calculating a reconciliation factor.

Any balance transferred to this rider from Rider RR shall be reflected in an ordered reconciliation factor in this rider and shall be charged or credited to all customers subject to this rider in accordance with the provisions under this rider for calculating a reconciliation factor.

* Any amounts remaining from or in excess of the 20% deducted from the overcharge for the period January 1, 1989 through June 30, 1990, as provided in the First Interim Order on Remand, or after payment of refund amounts under Rider TR, and as to which no customer or attorney claims as provided in the First Interim Order on Remand have been filed within two years, or which remain after settlement or adjudication of such claims, will flow to the then-current customers through the automatic reconciliation factor of the fuel adjustment clause.

* The differences between the computed amounts to be refunded and the actual refunds and which are not accounted for in Riders RR or TR shall be charged or credited to customers through reconciliation factors through the December 1992 billing cycle and shall earn interest at the legal rate specified in the First Interim Order on Remand.

The Company shall provide refunds to customers as provided in the First Interim Order on Remand not later than through the end of the December 1992 billing cycle.

The automatic reconciliation factor shall be adjusted consistent with the adjustment to the Ro factor to reflect the First Interim Order on Remand.

SCHEDULE AL-TOU

GENERAL SERVICE - LARGE - TIME METERED

APPLICABILITY

Applicable to all customers, including customers receiving three-phase residential common use service, who request service on this schedule and whose maximum monthly demand equals, exceeds, or is expected to equal or exceed 20 kW; to existing Schedule A customers whose maximum monthly demand is less than 20 kW who request service under this schedule on an optional basis; to any Schedule A customer whose monthly demand has been equal to or exceeded 20 kW for 12 consecutive months; and to existing Schedule AD customers whose maximum monthly demand exceeds 500 kW for three consecutive months. Any customer whose maximum monthly demand has fallen below 20 kW for three consecutive months may, at their option, elect to continue service under this schedule or be served under any other applicable schedule.

Non-profit group living facilities taking service under this schedule may be eligible for a 15% low-income rate discount on their bill, if such facilities qualify to receive service under the terms and conditions of Schedule E-LI.

TERRITORY

Within the entire territory served by the utility.

RATES FOR DEFAULT TIME PERIODS

	Per Meter Per Month
Service Charge	$40.00

Service Voltage	Secondary		Primary		Transmission	
Season	Summer	Winter	Summer	Winter	Summer	Winter
Demand Charge:						
Per kW of Non-Coincident Demand	$4.20	$4.20	$3.35	$3.35	$0.95	$0.95
Per kW of Maximum Peak-Period Demand	$18.62	$4.32	$18.14	$4.21	$11.41	$1.86
Energy Charge:						
Peak Period Base Energy per kWh	$.05220	$.03203	$.05000	$.03035	$.04666	$.02779
ECAC and AER per kWh	.03364	.03364	.03364	.03364	.03364	.03364
Total per kWh	$.08584	$.06567	$.08364	$.06399	$.08030	$.06143

(Continued)

SDGE San Diego Gas & Electric Company
San Diego, California

Revised Cal. P.U.C. Sheet No. 7838-E
Cancelling Revised Cal. P.U.C. Sheet No. 7621-E

SCHEDULE AL-TOU

RATES FOR DEFAULT TIME PERIODS (Continued)

Service Voltage	Secondary		Primary		Transmission	
Season	Summer	Winter	Summer	Winter	Summer	Winter
Energy Charge:						
Semi-Peak Period						
Base Energy per kWh	$.01027	$.01046	$.00927	$.00947	$.00776	$.00796
ECAC and AER per kWh	.03364	.03364	.03364	.03364	.03364	.03364
Total per kWh	$.04391	$.04410	$.04291	$.04311	$.04140	$.04160
Off-Peak Period						
Base Energy per kWh	$.00114	$.00150	$.00059	$.00094	$-.00028	$.00007
ECAC and AER per kWh	.03364	.03364	.03364	.03364	.03364	.03364
Total per kWh	$.03478	$.03514	$.03423	$.03458	$.03336	$.03371

Time Periods for Default Rates:

All time periods listed are applicable to local time.
The definition of time will be based upon the date service is rendered.

	Summer May 1 - Sept 30	Winter All Other
On-Peak	11 a.m. - 6 p.m. Weekdays	5 p.m. - 8 p.m. Weekdays
Semi-Peak	6 a.m. - 11 a.m. Weekdays	6 a.m. - 5 p.m. Weekdays
	6 p.m. - 10 p.m. Weekdays	8 p.m. - 10 p.m. Weekdays
Off-Peak	10 p.m. - 6 a.m. Weekdays	10 p.m. - 6 a.m. Weekdays
	Plus Weekends & Holidays	Plus Weekends & Holidays

Where the billing month contains time from both April and May or September and October, the on-peak period demand charges will be based on the demands registered in each month, weighted by the number of days billed in each month. Energy will be billed on the basis of the time period and season in which the usage occurred.

Non-Standard Seasonal Changeover:
Customers may select on an optional basis to start the summer billing period on the first Monday of May and to start the winter billing period on the first Monday of October. Customers electing this option will be charged an additional $100 per year for metering equipment and programming.

(Continued)

Advice Ltr. No. 885-E
Decision No. 93-07-050

Issued by
RONALD K. FULLER
Vice President
Governmental & Regulatory Services

Date Filed July 30, 1993
Effective August 1, 1993
Resolution No.

SCHEDULE AL-TOU

Time Periods for Default Rates: (continued)

Holidays:
The holidays specified in this schedule are: New Year's Day, Washington's Birthday, Memorial Day, Independence Day, Labor Day, Veterans Day, Thanksgiving Day and Christmas Day.

When any holiday listed above falls on Sunday, the following Monday will be recognized as an off-peak period. No change in off-peak period will be made for holidays falling on Saturday.

RATES FOR OPTIONAL TIME PERIODS

	Per Meter Per Month
Service Charge	$40.00

Service Voltage	Secondary		Primary		Transmission	
Season	Summer	Winter	Summer	Winter	Summer	Winter
Demand Charge:						
Per kW of Non-Coincident Demand	$4.20	$4.20	$3.35	$3.35	$0.95	$0.95
Per kW of Maximum Peak-Period Demand	$20.91	$4.32	$20.37	$4.21	$12.82	$1.86
Energy Charge: Peak Period						
Base Energy per kWh	$.06276	$.03203	$.06029	$.03035	$.05655	$.02779
ECAC and AER per kWh	.03364	.03364	.03364	.03364	.03364	.03364
Total per kWh	$.09640	$.06567	$.09393	$.06399	$.09019	$.06143
Energy Charge: Semi-Peak Period						
Base Energy per kWh	$.01567	$.01046	$.01455	$.00947	$.01285	$.00796
ECAC and AER per kWh	.03364	.03364	.03364	.03364	.03364	.03364
Total per kWh	$.04931	$.04410	$.04819	$.04311	$.04649	$.04160

(Continued)

SDGE San Diego Gas & Electric Company
San Diego, California

Revised Cal. P.U.C. Sheet No. 7840-E
Cancelling Revised Cal. P.U.C. Sheet No. 7623-E

SCHEDULE AL-TOU

RATES FOR OPTIONAL TIME PERIODS (Continued)

Off-Peak Period						
Base Energy per kWh	$.00114	$.00150	$.00059	$.00094	$-.00028	$.00007
ECAC and AER per kWh	.03364	.03364	.03364	.03364	.03364	.03364
Total per kWh	$.03478	$.03514	$.03423	$.03458	$.03336	$.03371

Time Periods for Optional Rates:

All time periods listed are applicable to local time.
The definition of time will be based upon the date service is rendered.

	Summer May 1 - Sept 30	Winter All Other
On-Peak	12 p.m. - 6 p.m. Weekdays	5 p.m. - 8 p.m. Weekdays
Semi-Peak	6 a.m. - 12 p.m. Weekdays	6 a.m. - 5 p.m. Weekdays
	6 p.m. - 10 p.m. Weekdays	8 p.m. - 10 p.m. Weekdays
Off-Peak	10 p.m. - 6 a.m. Weekdays Plus Weekends & Holidays	10 p.m. - 6 a.m. Weekdays Plus Weekends & Holidays

Where the billing month contains time from both April and May or September and October, the on-peak period demand charges will be based on the demands registered in each month, weighted by the number of days billed in each month. Energy will be billed on the basis of the time period and season in which the usage occurred.

Non-Standard Seasonal Changeover:
Customers may select on an optional basis to start the summer billing period on the first Monday of May and to start the winter billing period on the first Monday of October. Customers electing this option will be charged an additional $100 per year for metering equipment and programming.

Holidays:
The holidays specified in this schedule are: New Year's Day, Washington's Birthday, Memorial Day, Independence Day, Labor Day, Veterans Day, Thanksgiving Day and Christmas Day.

When any holiday listed above falls on Sunday, the following Monday will be recognized as an off-peak period. No change in off-peak period will be made for holidays falling on Saturday.

(Continued)

SCHEDULE AL-TOU

VOLTAGE LEVELS

Service voltage levels are defined as follows:

Secondary - service taken below 2.00 kV.

Primary - service taken at or above 2.00 kV but below 25.00 kV from regularly available facilities.

Transmission - service taken at 25.00 kV and above from regularly available facilities.

LIMITERS

Average Rate Limiter:
The average rate for service under this schedule will be limited to $5.00 per kWh for all charges excluding the service charge and standby charges (if any). If the total billed energy and demand charges, on a per kWh basis, exceed $5.00 per kWh then $5.00 per kWh is substituted for that portion of the bill.

On-Peak Rate Limiter:
The on-peak rate limiter only applies to customers taking service in conjunction with Schedules S or S-I. If, on a per kWh basis, the total charge for peak period demand and energy exceeds $0.77 per kWh summer or $0.30 per kWh winter, the bill for that service will be reduced such that the applicable $0.77 or $0.30 per kWh limit is not exceeded. This limiter only applies to energy and demand taken as backup service.

When a customer takes service in conjunction with Schedules S or S-I, a calculation is made in order to determine what demand and usage is subject to the $0.77 or $0.30 per kWh on-peak limiter and what is subject to the $5.00 per kWh average rate limiter. If a standby customer has a forced outage, that is demonstrated to the reasonable satisfaction of the utility within 60 days of occurrence, the on-peak demand and energy associated with the contracted standby kW are subject to the on-peak rate limiter. All demand and usage not subject to the on-peak rate limiter is subject to the average rate limiter.

Energy Cost Adjustment and Annual Energy Rate (AER):
An Energy Cost Adjustment, as specified in Section 9. of the Preliminary Statement, and an AER, will be included in each bill for service. The Energy Cost Adjustment and AER amount shall be the product of the total kilowatt-hours for which the bill is rendered, multiplied by the Energy Cost Adjustment and AER rates shown above.

Franchise Fee Differential:
A franchise fee differential of 1.9% will be applied to the monthly billings calculated under this schedule for all customers within the corporate limits of the City of San Diego. Such franchise fee differential shall be so indicated and added as a separate item to bills rendered to such customers.

(Continued)

SCHEDULE AL-TOU

SPECIAL CONDITIONS

1. Voltage Regulators. Voltage regulators, if required by the customer, shall be furnished, installed, owned, and maintained by the customer.

2. Maximum Demand. The maximum demand shall be the average kilowatt input during the fifteen-minute interval in which the consumption of electric energy is greater than in any other fifteen-minute interval in the billing period as indicated or recorded by instruments installed, owned and maintained by the utility, but not less than the diversified resistance welder load computed in accordance with the utility's Rule 2F-2b.

   In the case of hoists, elevators, furnaces, or other loads where the energy demand is intermittent or subject to violent fluctuations, the utility may base the maximum demand upon a five-minute interval instead of a fifteen-minute interval.

   In case the maximum demand has not been measured, it may be determined by test at the option of the utility.

3. Non-Coincident Demand Charge. The non-coincident demand will be based on the kilowatts of maximum demand measured at any time during the month. For billing purposes the non-coincident demand charge will be based on the higher of the current month's non-coincident demand or 50% of the highest non-coincident demand occurring during the previous eleven months. In the application of the 50% provision, only demands created in months during which the customer received service under this schedule will be used when customer's placement on the tariff is mandatory. In the case of customers paying for standby service under Schedules S or S-I, if a forced or scheduled outage of the customer's generating system during the billing period is demonstrated to the reasonable satisfaction of the utility within 60 days of occurrence, the level of that outage (not to exceed the amount of the contracted standby level), on a kW basis, is subtracted from the recorded demand in the applicable month in the non-coincident demand charge billing calculation.

4. Peak-Period Demand Charge. The demand charge will be based on kilowatts of maximum demand measured each billing period during the on-peak period. Demands created by the scheduled maintenance of a customer's self generation system (not to exceed the amount of the contracted standby level) will be subtracted from the measured peak-period demand used in calculating the demand charge, provided that the maintenance schedule has been previously approved by the utility.

(Continued)

SCHEDULE AL-TOU

SPECIAL CONDITIONS (Continued)

5. Power Factor Adjustment. This condition shall apply to all customers whose monthly demand has exceeded 300 kilowatts during any month over the last 12 months of recorded billing. If by test a customer's reactive demand exceeds 48% of the kilowatt demand, then the customer shall, upon receiving written notice from the utility, install and operate compensating equipment to reduce the reactive demand to 48% of the kilowatt demand. If such correction is not made within 6 months, the utility will at the customer's expense, furnish, install and maintain the necessary instrument transformers, test facilities and meter(s) required to measure the kilovar demand. Any additional facilities such as fuses, meter sockets, meter and instrument transformer housings required with the meter installation will be furnished, installed and maintained by the customer in accordance with the utility's standards. The customer shall henceforth receive an additional charge of 21 cents per kilovar for all kilovar billing determined as follows:

(a) Customers not operating generators in parallel with the utility's system:

kilovar billing = (maximum kilovar demand) - (0.48 x maximum kilowatt demand)

(b) Customers operating generators in parallel with the utility's system:

kilovar billing = (maximum kilovar demand) - [0.48 x (maximum kilowatt demand) - (maximum kilowatts generated)]

Notes: (1) If the kilovar billing is computed to be a negative number, then the power factor adjustment to the customer's monthly billing shall be $0.00.

(2) The maximum kilovar demand in any month shall be the average kilovar input during the fifteen-minute interval in which the consumption of reactive energy is greater than in any other fifteen-minute interval in the month.

(Continued)

SCHEDULE AL-TOU

SPECIAL CONDITIONS (Continued)

6. Time-of-Use Meter Malfunction

   a. Digital Pulse Recorder Malfunction. In the event that the digital pulse recorder (DPR) malfunctions during the billing period, the energy sales will be based on the mechanical meter reading. Where the malfunction existed for less than 25% of the billing period, the energy sales will be prorated to time periods based on the energy division during the period when the DPR was working properly. Where the malfunction time exceeds 25% of the billing period, the energy sales will be prorated to time periods based on the energy division during the three previous calendar months. If the DPR functions properly for more than 25% of the billing period, the demand charge will be based on the maximum demand as measured during the period of correct DPR functioning. In the event that the DPR malfunctions for more than 75% of the billing period, the demand charge will be based on the average of the three previous demand charges.

   b. Failure of Meter Timing. In the event that a timing device, other than a DPR, on the time-of-use meter fails, causing the On-Peak and Off-Peak energy consumptions and billing demands to be incorrectly registered, the energy sales and billing demand will be prorated to time periods based on the energy division and billing demand during the three previous billing periods.

7. Reconnection Charge. In the event that a customer terminates service under this schedule and re-initiates service at that same location within 12 months, there will be a reconnection charge equal to the charges which would have been billed had the customer not terminated service but not received any energy.

8. Miscellaneous. This schedule is not applicable to standby, auxiliary service or service operated in parallel with a customer's generating plant unless service is taken in combination with other schedules specifically waiving these provisions.

(Continued)

SCHEDULE AL-TOU

SPECIAL CONDITIONS (Continued)

9. Limitation of Optional Time Period Availability. At the utility's sole option, the optional time period provision of this schedule is available to no more than ten additional customers annually and; service will be provided in the order in which requests are received.

10. Time Period and Seasonal Changeover Switching Limitation. Customers who elect the optional time period of this schedule will be prohibited from switching service to the regular time period for a 12-month period. Customers who elect the nonstandard seasonal changeover option of this schedule will be prohibited from switching service to the regular seasonal changeover for a 12-month period.

11. Limitation on Non-Standard Seasonal Changeover Availability. At the utility's sole option, the optional non-standard seasonal changeover provision is available to no more than ten additional Schedule AL-TOU and Schedule A-6 TOU customers annually and; service will be provided in the order in which requests are received.

HOUSTON LIGHTING & POWER COMPANY
HL&P 67

LARGE GENERAL SERVICE-LGS

AVAILABILITY

At all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the premises to be served. Where adequate capacity or service of the type desired by the customer is not adjacent to the premises to be served, additional contract arrangements may be required prior to service being furnished.

APPLICATION

To any customer for all Electric Service supplied at one premises through one Point of Delivery and measured through one Meter. Not applicable to Standby service except in conjunction with appropriate agreements. Applicable to Temporary service subject to the provisions of the Service Extension Policy. The service furnished may not be remetered or submetered by the Customer for resale except pursuant to lawful submetering regulations of a regulatory authority with jurisdiction.

TYPE OF SERVICE

Three phase, 60 hertz alternating current and at one of the Company's standard service voltages as described in the Company's Service Standards.

MONTHLY BILL

The monthly bill shall be the sum of calculations made under (1) below or the calculations made under (2) below, whichever is higher, plus the applicable adjustments stated under (3) below.

(1) Rate

(a) Facilities Charge	\$530 per month.
(b) Demand Charge	
Primary Kva Charge	\$4,092 which includes 600 Primary Kva plus \$6.82 per Kva for all additional Primary Kva
Secondary Kva Charge	\$2.40 per Kva for all Secondary Kva

(c) Energy Charge — $.025734 per Kwh for the first 295 Kwh per Primary Kva plus

$.007540 per Kwh for all additional Kwh.

(d) Fuel Charge — Amount determined in accordance with Rider FC.

(2) Minimum Bill

The Primary Kva Charge applicable to the current month plus the monthly Facilities Charge.

(3) Adjustment

Plus an amount determined in accordance with Rider PCRF.

DEFINITION OF ON-PEAK HOURS AND OFF-PEAK HOURS

Company's On-Peak hours, for the purposes of this rate schedule, are designated as being from 8 a.m. to 10 p.m. each Monday through Friday starting on May 15 and continuing through October 15 each year. Labor Day and Independence Day (July 4) shall not be considered On-Peak. If July 4 occurs on Sunday then the following Monday shall not be considered On-Peak. The Company's On-Peak hours may be changed from time to time and Customer will be notified 12 months prior to such change becoming effective.

Company's Off-Peak hours, for the purposes of this rate schedule, are all hours of the year not designated as On-Peak hours.

DEFINITION OF ON-PEAK KVA, ANNUAL ON-PEAK KVA AND OFF-PEAK KVA

The terms "On-Peak Kva", "Annual On-Peak Kva" and "Off-Peak Kva" shall be defined as follows:

(1) On-Peak Kva is the average Kva supplied during the four fifteen minute periods of maximum use during the On-Peak hours of the billing month.

(2) Annual On-Peak Kva is the highest On-Peak Kva established in the 12 months ending with and including the current billing month. For billing purposes, Customer's Annual On-Peak Kva shall not be less than 600 Kva.

(3) Off-Peak Kva is the average Kva supplied during the four fifteen minute periods of maximum use during the Off-Peak hours of the billing month.

DETERMINATION OF PRIMARY KVA AND SECONDARY KVA TO BE USED IN CALCULATING THE BILL

The Primary Kva and the Secondary Kva to be used in calculating the Monthly Bill shall be determined in accordance with the following provisions:

(1) If the Off-Peak Kva is equal to or less than the Annual On-Peak Kva, the highest of the following will be billed as Primary Kva:

(a) The On-Peak Kva;
(b) The Off-Peak Kva;
(c) 85% of the Annual On-Peak Kva; or
(d) 600 Kva.

(2) If the Off-Peak Kva is greater than the Annual On-Peak Kva, then Annual On-Peak Kva, but not less than 600 Kva, will be billed as Primary Kva and the excess of the Off-Peak Kva over the Annual On-Peak Kva will be billed as Secondary Kva.

The above provision (2) is not applicable to either (a) new customers taking service for the first time during the period starting October 16 and continuing through May 14 or (b) for existing customers operating new facilities during such period. Under such circumstances, unless the Annual On-Peak Kva has been determined by mutual agreement, the Off-Peak Kva will be billed as Primary Kva until the following May 15.

PAYMENT

Bills are due when rendered. A bill for electric service is delinquent if payment is not received by the Past Due Date shown on the Electric Service Bill. The Past Due Date will not be less than sixteen (16) days from the date the bill is mailed to Customer. A one-time late payment charge of 3% of the entire bill exclusive of sales tax will be assessed if the total amount due is not received on or before the Past Due Date.

CONTRACT PERIOD

Not less than 1 year.

NOTICE

Electric Service furnished under this rate schedule is subject to the Company's Terms and Conditions for the Sale of Electric Service, Sheet No. E1.

HOUSTON LIGHTING & POWER COMPANY
HL&P 7550

FUEL COST FACTOR - RIDER FC

Pursuant to the Substantive Rules of the Public Utility Commission of Texas, Section 23.23(b)(2), all applicable rate schedules shall be subject to a Fuel Charge determined by multiplying the Kwh for the current billing month times the appropriate Fuel Cost Factor. The Fuel Cost Factor will be adjusted to recognize differences in losses due to voltage levels of service. The Fuel Cost Factors are as follows:

Overall Factor	$.019649 /Kwh
Distribution Voltage	$.019924 /Kwh
Transmission Voltage	$.018765 /Kwh

HOUSTON LIGHTING & POWER COMPANY

OFFICE MEMORANDUM

TO: Distribution

December 16, 1992

FROM: K. J. Ousdahl

SUBJECT: **PCRF FACTORS EFFECTIVE JANUARY 1993**

Purchased Power Cost Recovery (PCRF) Factors have been calculated to collect the difference between firm cogeneration payments in base rates and projected 1993 firm payments to cogenerators of $25.3 million. This amount represents an approximately $13 million increase over 1992 due to projected firm cogeneration contract escalations. Both old and new factors are listed below. The new factors will be effective with the January, 1993 billing month.

	Old Factors Effective January 1992	New Factors Effective January 1993
RS	$ .000372	$ .000670
MGS	.000307	.000523
LGS	.000208	.000449
LOS-A	.000173	.000273
LOS-B (per Kva)	.170497	.209959
TNP	(.001542)	(.000558)
SPL	.000181	.000313
CLS	.000175	.000266

MLP:mp

Distribution:

R. S. Letbetter
J. S. Brian
L. G. Brackeen
A. D. Maddox
T. R. Standish
A. Abramowitz
C. T. Breuer
W. L. Bryant
R. A. Dowdall
R. C. Ehmer
M. R. Ferrell
D. G. Gartman
P. B. Griffin
T. C. Kolkhorst
F. J. LeBlanc
R. Q. McWhirter
P. A. Morrow
D. S. Murphy
G. E. Nichols
J. N. Purdue
H. W. Roesler
C. L. Sadowsky
J. F. Schaefer
T. M. Sobey
R. S. Turnbull
E. H. Turner
W. L. Ulrich
R. Wright
Z. E. Wright
R. A. Zapalac

TOTAL P.03

CITY OF BRENHAM

210 NORTH PARK STREET P. O. BOX 1059
BRENHAM, WASHINGTON COUNTY, TEXAS 77833

~~ALL SERVICES~~
TARIFF

~~ELECTRIC RATE SCHEDULE~~
SECTION TITLE

400
SECTION NUMBER

RE~~VISED~~ Sheet No. 440

Rev. No. ______ Sheet No. ______

Effective January 25, 1991
Month Date Year

SMALL INDUSTRIAL SERVICE

RATE SCHEDULE E-G

APPLICABILITY

This rate is applicable to customers receiving electrical service for any purpose other than use in individually metered residential dwellings, and includes service to temporary service installations.

AVAILABILITY

This rate schedule is available to all customers whose electric requirements for all uses exceed three hundred (300) kilowatts of maximum demand during any month during any twelve (12) month period, but whose requirements do not equal or exceed five thousand (5000) kilowatts of maximum demand.

MONTHLY BASE RATES

The monthly base rates shall be the sum of the following charges:

Customer Charge $ 100.00 per month

Demand Charge
Non-coincident peak (NCP) KW demand charge
$ 1.260 3 per billing NCP KW demand

Coincident peak (CP) KW demand charge Summer
On peak $ 9.061 per CP KW demand
Off peak $ 6.465 per CP KW demand

Energy Charge
$ 0.00880 per KWH

Capacity Charge

$ 0.2400 KVA for all transformer capacity installed to serve the customer's facility.

CITY OF BRENHAM

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ALL SERVICES
TARIFF

ELECTRIC RATE SCHEDULE.
SECTION TITLE

400
SECTION NUMBER

REVISED Sheet No. 441

Rev. No. ________ Sheet No. ________

Effective January 25, 1991
Month Date Year

DETERMINATION OF BILLING KW DEMAND

1. Non-coincident peak (NCP) kw demand charge. The non-coincident peak billing kw demand charge shall be the highest measured non-coincident kw demand established during the billing period.

2. Coincident peak (CP) kw demand. The coincident peak kw demand shall be the kw demand established during the LCRA system peak hour (coincident peak) during the billing period. For the months of June, July, August, and September, the Summer CP kw demand charge will be applied to the coincident peak kw demand. For all other months, the off-peak demand charge will be applied to the coincident peak kw demand.

MINIMUM MONTHLY CHARGES

The minimum monthly bill shall be the customer charge plus the non-coincident peak demand charge plus the coincident peak demand charge plus the capacity charge.

BILLING ADJUSTMENTS

1. In addition to the base charges, each customer's monthly bill shall include an appropriate fuel cost charge as explained on Sheet No. 485.

2. In addition to the base charges and fuel cost charges, each customer's monthly bill shall include a power cost adjustment charge, if applicable, as explained on Sheet No. 495.

3. In addition to the base charges, fuel cost charges, and power cost adjustment charges, the customer shall be billed for all taxes applicable to the sale of electricity.

CITY OF BRENHAM

210 NORTH PARK STREET P. O. BOX 1059
BRENHAM, WASHINGTON COUNTY, TEXAS 77833

ALL SERVICES — TARIFF | REVISED Sheet No. 442
ELECTRIC RATE SCHEDULE. — SECTION TITLE | Rev. No. ______ Sheet No. ______
400 — SECTION NUMBER | Effective January 25, 1991 (Month Date Year)

TERM OF PAYMENT

The bills rendered under this schedule are net and will be increased by 10% if not paid within fifteen (15) days after the date of the bill.

CHARACTER OF SERVICE

Electric service supplied under this rate schedule shall be 60 cycle alternating current delivered at a single point of service to be designated by the City, at the City's choice of the following standard voltage:

120/208 volts, three phase
120/240 volts, three phase
240/480 volts, three phase
277/480 volts, three phase
7200/12470 volts, three phase

SPECIAL CONDITIONS OF SERVICE

1. Service rendered under this schedule is subject to the City's Rules and Regulations in effect from time to time.

2. Service will be rendered under this schedule when the City has facilities immediately adjacent to the customer's premise. If a power line extension is required to provide service to the customer, the customer's cost of the line extension will be determined in accordance with the City's extension policy in effect at the time of the extension.

3. The customer shall control voltage fluctuations caused by his equipment at his expense. A customer's equipment shall not cause voltage fluctuations that exceed 1% on the City's primary distribution system.

CITY OF BRENHAM

210 NORTH PARK STREET P. O. BOX 1059
BRENHAM, WASHINGTON COUNTY, TEXAS 77833

ALL SERVICES TARIFF	REVISED Sheet No. 443
ELECTRIC RATE SCHEDULE SECTION TITLE	Rev. No. Sheet No.
400 SECTION NUMBER	Effective January 25, 1991 Month Date Year

4. A power factor penalty shall be assessed if the necessary equipment for determining power factor is installed and if the power factor during the coincident peak kw demand period is less than 0.90.

   The power factor penalty shall be calculated by increasing the measured coincident peak kw billing demand such that the corrected billing demand and measured KVAR yield a calculated power factor of 0.90. If the measured power factor is 0.90 or greater, the billing kw demand shall be the kw demand in accordance with the appropriate schedule.

   The additional metering equipment necessary to measure or compute KVAR or power factor may be installed at any demand metered customer without notice at the discretion of the City.

APPENDIX C

Video Script

SCRIPT FOR TRAINING VIDEO

"DEMAND, ENERGY & POWER FACTOR"

INTRODUCTION

This video is designed to provide information for facility managers about electrical demand, utility rate block extenders, and power factor.

Most people understand that energy at their homes is measured and billed in kilowatt-hours.

However, energy bills at commercial and industrial plants are more complex, with many factors that have important impacts on costs.

This video explains some of the major components of your billing so that you can take steps to most effectively control your electrical costs.

DEMAND

The rate at which you use energy at your plant is defined as demand. Under most billing rate structures it is expressed in kilowatts, but some utilities use kilovolt-amperes.

As an example, the demand you use can be compared to filling a swimming pool in your backyard.

For this example, the two methods available to fill the pool are either a garden hose or a fire hose.

The garden hose is like low electrical demand, and there is only a small outlay of money and material for the hose itself. However, the rate at which you can fill the pool is very slow.

If you could use a fire hose, similar to high demand, you would have a large outlay of money and material for the hose and fire plug -- but the advantage is that the pool will fill much faster.

Equating this to demand, the faster the rate of energy flow (water in this example) the higher the capital cost for equipment to provide the same total amount of energy (gallons of water to fill the pool).

A utility must have larger electrical service capacity for a plant which runs all its equipment at once compared to one which can stagger equipment use over time.

Utilities pass this cost on to customers in a demand charge. One way to lower costs for industrial and commercial customers is to lower demand.

In a moment we will talk more about a simple example of lowering demand, but first, let's talk some more about why electrical demand charges occur.

Electric Load Leveling:

*** show flip chart of daily utility load*** (see copy at end of script)

This is the typical load a utility experiences during a peak summer 24-hour period.

Because electric utilities generally do not store energy, they must have sufficient equipment capacity to produce the highest peak demand during the day (point to the peak demand) at the time it is needed.

At other times some of this equipment is idle.

As you can see by this chart, most of the demand on the utility company is during the normal 8 a.m. to 5 p.m. workday.

The maximum daily peak demand in the South normally occurs about 6 p.m., when most people return home to cook, watch TV, and turn on their air conditioners.

The utility meets the demand as it occurs, and then idles equipment as it declines (point to graph).

A utility plant would like to lower both the maximum demand and also spread it evenly throughout the day to better use their equipment.

The method for the utility to do this is called "load or demand leveling."

Example:

A simple example for load or demand leveling would be a process which requires two machines, each with a 100 hp motor for an eight-hour shift, attended by one or more workers.

If you instead use one machine with its 100 hp motor for 16 hours, the production would theoretically remain the same but the electric demand for the same process would be halved.

Four points are important here.

(1) Production is the same.
(2) Demand is cut in half.
(3) Demand charges are reduced.
(4) But, the shift or work day length has increased.

Routinely, plants need only increase the length of work day to see a savings in their electrical demand.

BLOCK EXTENDERS

There are several different types of utility energy rate structures.

One is a flat block structure with a flat rate, such as 3¢/kWh, for all the consumption, in kWh, of the plant.

Another typical rate structure is the fixed declining block. For example, this might cost 3¢/kWh for the first block of energy consumption and 1¢/kWh for the second block.

The size of the first block is fixed at some value such as 100,000 kWh and the second block contains all energy consumed more than the amount in the first block.

A third typical rate structure is the flexible declining block. It might also have costs of 3¢/kWh for the first block of energy and 1¢/kWh for the second block.

This rate structure is dependent on the peak demand of the plant and cost savings for energy are available as a result of lowering demand.

** ***show flip chart of block structure*** (see copy at end of script)

Shown here is a two block, flexible, declining rate structure. In this case, the cost for consumption in the second block is cheaper than the first block.

The size of the more expensive block is determined by the peak demand of the plant times a block multiplier.

Example:

For example, let's say a plant has a peak demand of 2000 KW, a total consumption of 700,000 kWh per month, and a first block multiplier of 250 kWh/KW.

Multiplying the peak demand of 2000 KW by the block multiplier of 250 kWh/KW results in the first block size of 500,000 kWh. The remainder of the 700,000 kWh, or 200,000 kWh, is in the second block.

A first block energy charge of 3¢/kWh and a second block energy charge of 1¢/kWh, results in a total charge of $17,000 for the energy consumption for the month.

Reducing demand by 500 KW with the same consumption would decrease the size of the first block by 500 KW times 250 kWh/KW or 125,000 kWh's.

This energy would now be charged at the lower second block rate rather than the more expensive first block rate.

The savings would be $2,500 per month for this movement of energy from one block to the other. There would also be a demand charge savings.

Therefore, with the flexible, declining block structure savings can be realized by lowering demand. However, as has been illustrated here, the total energy consumption would not change.

POWER FACTOR

Power factor is closely related to demand. Very basically, power factor is a measure of how effectively your plant uses the electricity it buys.

Many billings do not list power factor, but if your plant is operating below some predetermined power factor percentage you may be penalized.

Typically, power factors less than 75% to 85% are associated with power factor cost penalties.

** ***Show the power triangle flip chart*** (see copy at end of script)

This is a graphical representation of real, apparent and reactive power in an AC circuit.

Real power is the power which the equipment actually uses to run, which does useful work on the plant floor. Real power is expressed in kilowatts.

Apparent power is the power the utility will supply to run your equipment. It is expressed in kilovolt-amperes.

The ratio of real power to apparent power is the power factor, which is normally expressed as a percent.

Increasing the power factor to unity, or 1.0, is desirable. This would mean that you would be using all of the apparent power supplied by the utility to run your electrical loads and do useful work.

This can be done by adding capacitors to inductive loads, such as electric motors.

If your plant has very large motors, the capacitors can be added to the motor circuits.

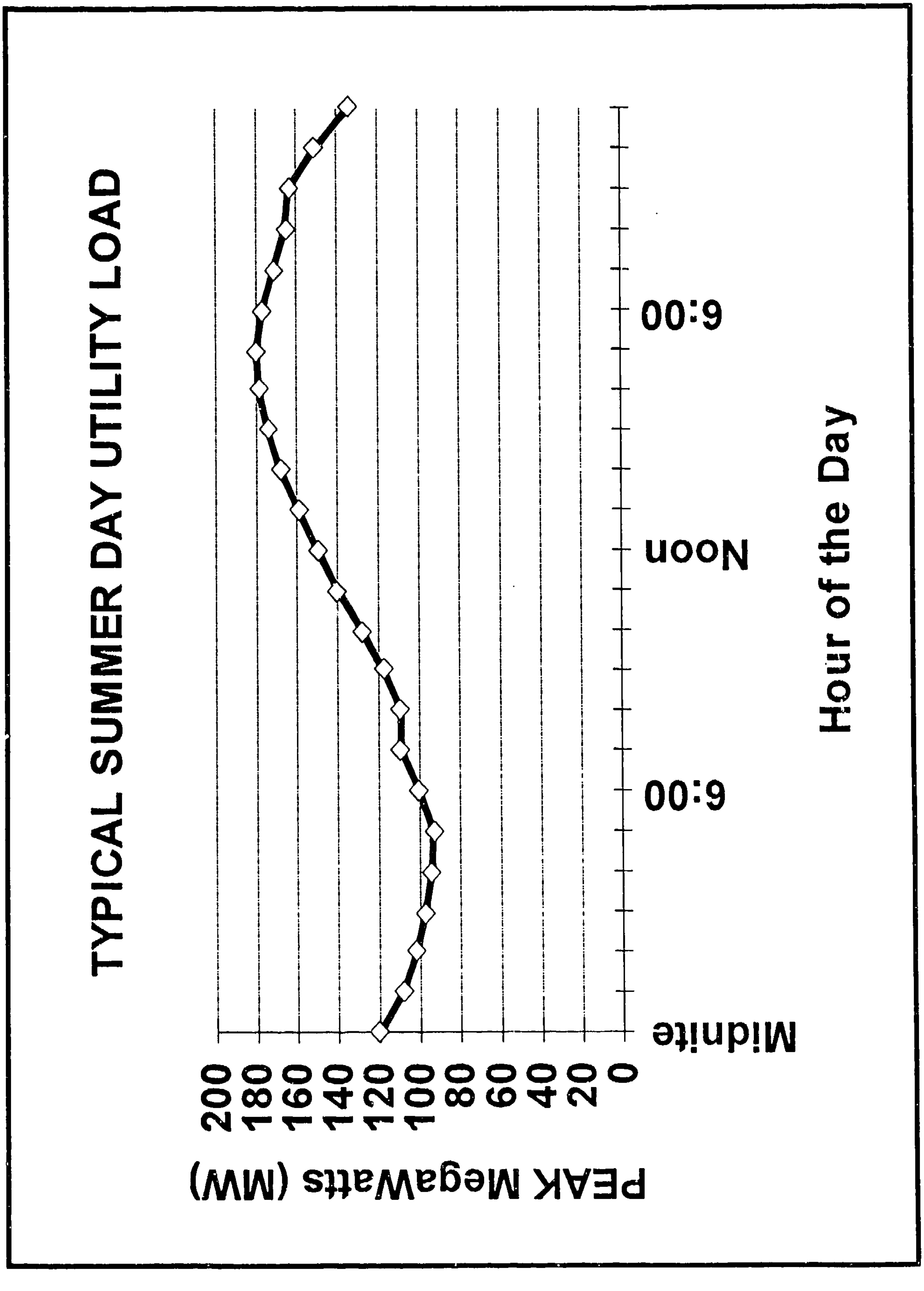
However, sometimes it is more desirable to increase the entire plant's power factor. This is done by adding a capacitance bank to the incoming electrical feed.

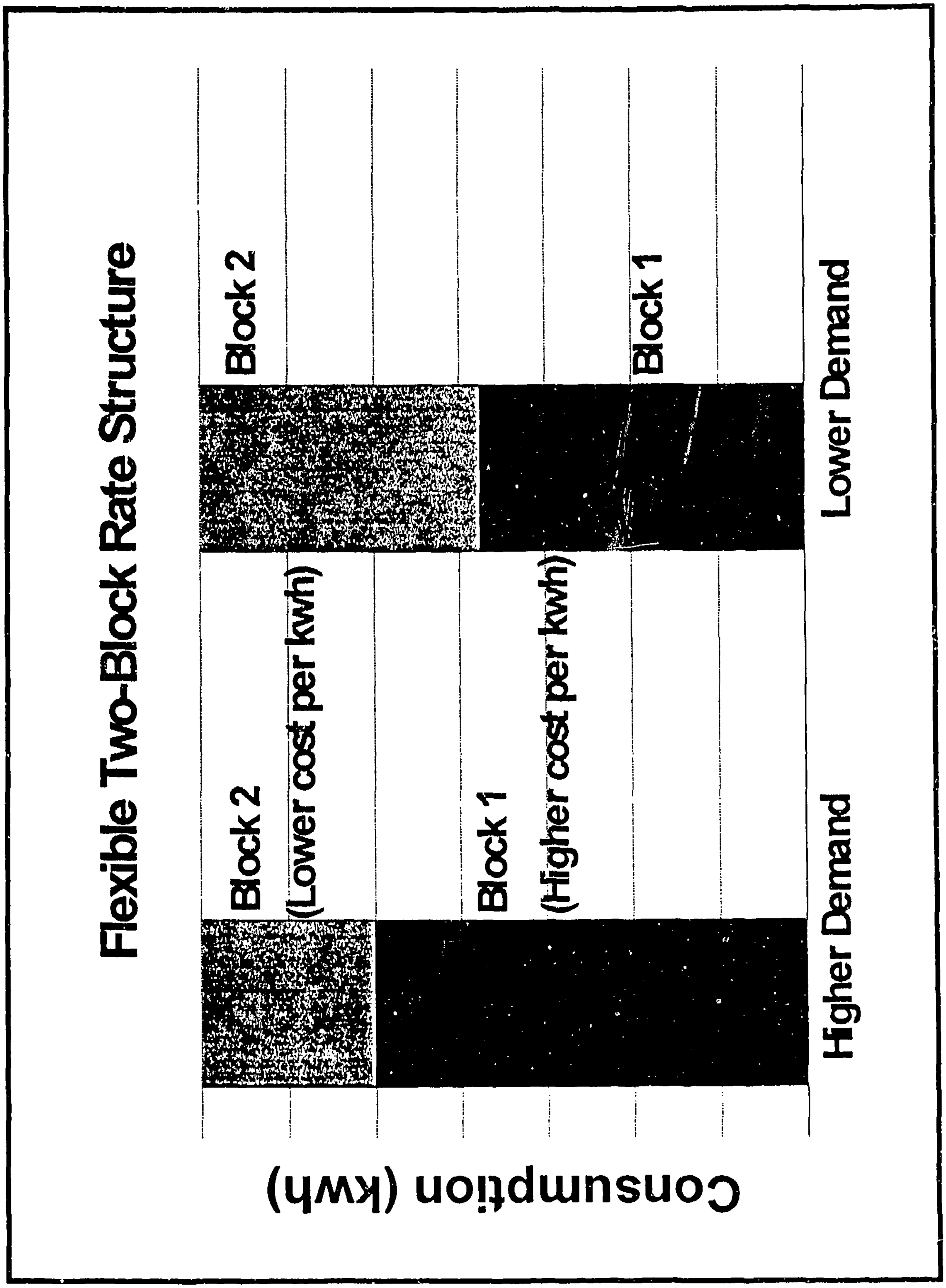
With help from the utility and a good electrical contractor this could save dollars and have a short simple payback. Many power factor correction projects payback in one or two years.

CONCLUSION

In this video, we have introduced you to the basics of electric demand, block extenders and power factor.

Using this information, along with a good energy efficiency program, we hope you get a better return for your electrical energy dollar.


TYPICAL SUMMER DAY UTILITY LOAD
PEAK MegaWatts (MW)
200
180
160
140
120
100
80
60
40
20
0
Midnite
6:00
Noon
6:00
Hour of the Day


Flexible Two-Block Rate Structure
Block 2
(Lower cost per kwh)
Block 1
(Higher cost per kwh)
Block 2
Block 1
Higher Demand
Lower Demand
Consumption (kwh)